EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD

Ontario

ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARINGS

VOLUME: 168

DATE: Tuesday, October 27, 1992

BEFORE:

HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

FARR & ASSOCIATES REPORTING INC.

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ENVIRONMENTAL ASSESSMENT BOARD
ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARING

IN THE MATTER OF the Environmental Assessment Act, R.S.O. 1980, c. 140, as amended, and Regulations thereunder;

AND IN THE MATTER OF an undertaking by Ontario Hydro consisting of a program in respect of activities associated with meeting future electricity requirements in Ontario.

Held on the 5th Floor, 2200 Yonge Street, Toronto, Ontario, Tuesday, the 27th day of October, 1992, commencing at 9:00 a.m.

VOLUME 168

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MS. G. PATTERSON	Member

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---Upon commencing at 9:00 a.m.

THE REGISTRAR: Please come to order. This hearing is now in session. Please be seated.

THE CHAIRMAN: Mr. Campbell?

MR. B. CAMPBELL: Mr. Chairman, I received yesterday from Mr. Poch a copy of the letter in which he requested subpoenas for certain Ontario Hydro officers. Mr. Poch and I intend to discuss this matter at some point today and hope to be able to bring some -- let me put it slightly differently.

If I have any submissions to make on the matter, I would like the opportunity to have that the conversation with Mr. Poch and then I may well have submissions on the matter.

THE CHAIRMAN: All right. I haven't studied the letter yet in any event.

Mr. Starkman, are you conducting the examination?

MR. STARKMAN: Thank you, Mr. Chairman. I don't know if the witness has been sworn yet.

THE CHAIRMAN: Yes. Swear the witness, please.

PETER J. LANZALOTTA; Sworn.

MR. STARKMAN: Thank you, Mr. Chairman.

I would like to introduce Peter

Lanzalotta who is an engineer who has been working in consulting in the area of utility planning for 20 years. Mr. Lanzalotta has prepared what has been marked as Exhibit 744, and I will just basically be asking him some brief questions about it, but this is his evidence in Exhibit 744, together with the appendices which have been marked as Exhibit 745 and 746.

DIRECT EXAMINATION BY MR. STARKMAN:

Q. Mr. Lanzalotta, I would like to just briefly begin, or begin by briefly reviewing your curriculum vitae and qualifications and they are at Appendix 1, or the first page of Exhibit 745.

Now, perhaps you could just tell the Board briefly the type of work you have been doing for the last years and in particularly with Whitfield Russell Associates?

A. For the last 10 years I have been working with Whitfield Russell Associates, since 1986 as a full partner, and worked at mostly in electrical power engineering doing studies involving reliability, appropriate reserve margin, capacity expansion planning, that being the types of capacity the utility is going to install when its reserve margin indicates a need.

I have also done a fair amount of work in ratemaking, cost allocation, rate design, computer modelling and some financial utility analysis work.

Q. Now, in your curriculum vitae you identify a number of places where you have given prior testimony. I am just wondering, could you identify whether any of these instances of prior testimony are with respect to reliability and reserve margin matters?

A. Yes. In Appendix 2, if we look on page 2, No. 9, Kansas Power and Light involved the capacity needed by the utility to render reliable service; No. 10 regarding Philadelphia Electric; No. 12 involving Duquesne Light Company; Nos. 14, 15, and 16 also; No. 18 to an extent. No. 18, it was not so much calling reserve margin into account of question as looking at the type of capacity needed to fulfil that reserve margin. Also No. 21 -- I'm sorry not 21. No. 20.

I guess out of the 29 here those would be the ones most directly relevant.

Q. Mr. Lanzalotta, can you tell us what you were asked by CEG to do with respect to Hydro's application?

A. I was asked to review Ontario Hydro's Balance of Power study, a 25 year study of the system

and Hydro's options for supplying the forecasted load on its system. I was asked primarily to concentrate my review in the areas of system reliability and the inclusion of transmission planning considerations into the planning process.

Q. Now, in Exhibit 744 you discuss basic reliability concepts. Can you explain these and how the reserve margin fits into that?

A. Certainly. Starting on page 6 of Exhibit 744 we have give a brief discussion on reliability planning concepts.

Basically in reliability planning, generation reliability planning more specifically, the goal is to supply enough generating capacity so that a basic level of reliability is going to be reached on the system. There are different ways to measure this reliability. It can be measured in terms of the amount of energy that you would expect to be left unsupplied given a particular amount of generating capacity, another way would be to measure the number of days on which you would have an outage given a particular amount of generating capacity.

In reliability planning you will set some type of target reliability index. In the case of Hydro they express this index in terms of system-minutes of

unsupplied energy. In terms of the loss of load probability concept, which I also address in my testimony, you are looking at the number of days per year that you will have an outage at the time of peak load.

Q. How did you proceed to analyze Hydro's 24 per cent planning reserve margin?

A. The first thing I did was to look at the basic make-up of Ontario Hydro's system, what type of generating capacity it had, when its peak load occurred, what kind of transmission inter-ties it had with neighbouring utilities, and tried to get a rough feel for the characteristics of Hydro's system.

Looking at those basic characteristics, I had reason to question the 24 per cent reserve margin.

Q. Why was that?

A. Well, typically, a typical reserve margin rule of thumb that we usually use is 20 per cent based on average utility characteristics. Now the Ontario Hydro system has a substantial amount of hydroelectric generating capacity, hydroelectric generating capacity tends to be more reliable than fossil-fired or nuclear-fired generating capacity. So typically utility systems with large percentage or a significant percentage of hydroelectric generating

capacity, you expect to see them to be more reliable than with systems without this, and typically the more reliable the system, the more reliable the generating capacity on the system, the lower the reserve margin, the lower the planning reserve margin you would expect to see that system use.

So, we looked at the amount of hydro generation, also the basic size of the system, because system size especially in relation to the types of generating units that are installed on the system can also be an indication of how high a reserve margin the utility is going to have to provide.

Where you have a system which has a very high peak load in relation to the largest generating units on that system, a forced outage of any one of these large generating units has a substantially smaller effect than would an outage of the same size unit on a smaller system. So that when the system is large compared to the largest generating units, typically you expect to see reserve margin, planning reserve margin that tends towards lower end of the range. So, from that respect, of course, Ontario Hydro, I believe, has the largest peak load of any utility in North America.

[9:13 a.m.]

And from that viewpoint I would be surprised to see a planning reserve margin as high as 24 per cent.

Q. So after this initial view of the general characteristics of the Hydro system, how did you then proceed?

A. We proceeded by studying the methods that Hydro uses to support its 24 per cent reserve margin. Primarily they use what they call frequency and duration model which utilizes criteria based on the amount of energy which is expected to be left unserved.

We attempted to get the data and the F&D model ourselves so that we could make some runs and perhaps vary some of the key parameters, key assumptions, that Ontario Hydro uses when it makes its determination.

Q. Were you able to get that information from Hydro to get the F&D model running?

A. Hydro provided us with the input data and what it told us was the F&D model. Initially what we had received from Hydro as the F&D model didn't appear to be complete; and after making a couple of runs with the model, we got back in touch with Hydro and it turned out that they felt there were some more pieces of the model that we hadn't been provided with.

We got some more pieces of the model and we tried again to make the runs initially just to duplicate the results that Ontario Hydro was getting. However, despite considerable effort and expense on our part, we never were able to really get the model to run.

Q. I'll come back to the F&D model. But being unable to get it to run, how did you then proceed to try and analyze the basis for Hydro's 24 per cent reserve margin assumption?

A. Since we couldn't get F&D to run, we decided that we would use a more traditional reliability planning means of analysis. And that was based on loss of load probability.

A significant percentage of the utilities in North America use or have in the recent past used loss of load probability as a basis for setting their generation planning reserve margin. The traditional utility target for loss of load probability is to supply enough generation so that load is lost due to shortage of generation a maximum of one day in 10 years or a 10 per cent chance of such an outage occurring every year.

We did a number of basic runs with our loss of load probability model to try to establish a

base case for the Hydro system and then we proceeded to look at a number of assumption changes from what Hydro used when it ran its model.

Q. In your paper you talk about establishing a benchmark; is that right?

A. That's correct.

Q. Doing a benchmark. What does that mean?

A. Okay. In running models, reliability models or actually many types of other models that attempt to replicate what happens on the utility system, you have to take into account that the utility system is very complex, has a large number of variables, and modelling -- what happens on the utility system is ambitious undertaking.

The purpose of the benchmark is to fine-tune the model so that given a particular set of operating assumptions it will duplicate the characteristics of the utility system.

So we established two benchmarks. In the data that we had on Ontario Hydro's system planning, we had data that indicated that with an assumption of zero outside assistance, a 30 per cent reserve margin would be necessary to attain a one day in 10 year LOLP.

We also had data that indicated that from

Hydro's modelling with 700 megawatts of outside assistance, a 26 per cent reserve margin was necessary to maintain a loss of load probability of one day in 10 years.

So the first thing we did was to fine-tune our model so that at a 30 per cent reserve margin and no outside assistance, our model would produce a one day in 10 year LOLP. And with an assumption of 700 megawatts of outside assistance, 26 per cent reserve margin would be required to achieve the same result.

Q. So those are the benchmarks you were using?

A. Those are the benchmarks.

Q. Now, you said you then proceeded to vary that, to vary the benchmarks or vary the assumptions to see what the results were.

A. That's correct. There are basically two assumptions that we were looking at to vary. The first has to do with the assumption of how many megawatts of emergency outside assistance should Hydro plan on being able to make use of when it sets its generation planning reserve margin.

During the 1980s Hydro has used an assumption of 700 megawatts of outside system

assistance. In looking at the 700 megawatt number, to me it seemed rather small in comparison to the peak load on the Ontario Hydro system which is in the range of, I think, 25,000 megawatts. It also seemed to be --

THE CHAIRMAN: Sorry, what did you say was 25,000 megawatts?

THE WITNESS: The load on the Ontario Hydro system.

THE CHAIRMAN: Yes, thank you.

THE WITNESS: It also seemed to me to be somewhat small in relation to the capability of Ontario Hydro's transmission ties with utility systems to which Hydro is interconnected.

So we decided to look at just what Ontario's ties could deliver and what the utility systems to the south might be capable of delivering in a moment of emergency on the Ontario Hydro system.

MR. STARKMAN: Q. And did you form an opinion as to the appropriate amount of interconnection assistance Ontario Hydro could rely on for planning purposes?

A. Yes, I did. In looking at both the capability of the transmission ties between Hydro and utilities to the south as well as the characteristics and capabilities of the utility systems that lie to the

south, I determined that a number of 3,200 megawatts was reasonable to use for planning purposes for outside assistance.

Q. Can you explain why you thought 3,200 was an appropriate number?

A. Yes, I can. As I said, we looked at basically two elements. The first element was the transmission inter-ties. Hydro obviously could not assume they could get more import assistance than it had transmission capacity to deliver. So we looked at what is called the first contingency incremental transfer capability of Ontario Hydro's transmission ties with both the New York Power Pool and utilities off in the direction of the Michigan area.

Now, what we mean by first contingency incremental transfer capability. First contingency means that you assume that your most critical facility is out of service. Incremental means that you take into account the firm transmission flows that are already scheduled over these lines. If the line is being used for a firm transmission transaction, then it's not available for emergency assistance.

So in looking at this characteristic of Ontario transmission ties to the south, I believe we found that an amount of capacity well in excess of

3,200 megawatts was available.

Q. Do you have an opinion as to the ability of these utilities to the south to be able to deliver this power? I mean you are saying there was transmission capability but what about availability of power.

A. That was the next step of our analysis. When a utility finds itself in a state of need and it has to make use of emergency assistance, these situations frequently occur with little or no warning. So, the first thing we wanted to look at was the amount of spinning reserve that the utilities connected to the south were in the habit of maintaining.

In looking at the New York Power Pool and the ECAR utilities which Hydro accesses through Michigan, we found that there was in excess of 3,200 megawatts of spinning reserve according to our calculations which was maintained on a regular basis. [9:25 a.m.]

So we felt that this was a reasonable estimation of the amount of emergency assistance that Hydro could be assured of getting in a time of emergency need.

Q. Mr. Lanzalotta, do you view the 3,200

megawatt number you have been talking as a conservative assumption or how would it fall in your range of assumptions?

A. I wouldn't say it is a very conservative assumption. I would say it would tend to make full use of the capabilities not only of Hydro's ties, but also of the spinning reserves to the south. I wouldn't say that it is a particularly ambitious estimate either, however.

I kind of view it as my opinion of the most reasonable assumption as to what would be available.

Q. Now, if Hydro were to use this number in calculating its target reserve, what impact would it have on the target reserve?

A. According to our calculations, it would lower Hydro's generation planning reserve margin target down to the range of about 16 per cent, if you just plug the number in and do the calculation.

Q. Okay. Yet in your paper you recommend 20 per cent?

A. Yes, for several reasons. First of all, the interconnection assistance was not the only assumption that we looked at varying. We also incorporated data from CEG's witness, Charles Komanoff,

as to nuclear performance, and we looked at what type of generation planning reserve margin target would produce target reliability given those assumptions as well. And when we ran those numbers, that caused the planning reserve margin target to increase slightly.

Q. What numbers did you use from Mr. Komanoff in terms of modelling a nuclear reliability?

A. Okay. He told us that the amount of required maintenance would increase by approximately 50 per cent from what Hydro was planning, and that the forced outage factor would increase by an amount of about 50 per cent. So we applied those relationships to the maintenance and forced outage characteristics that we had been using on the Ontario Hydro nuclear generation.

Q. What impact would that assumption have on the model?

A. That in itself causes the planning target reserve margin to increase, I think, by about 2 per cent, maybe slightly more, to something in the range of slightly above 18 per cent.

Q. So when you say that the model turns out 16 per cent, what nuclear reliability numbers would you use to get 16 per cent?

A. I believe we used data on nuclear

performance that we took from Hydro's LMSTM.

Q. So the two factors you varied then were the nuclear reliability numbers and the interconnection assistance?

A. That's correct.

Q. And what was your conclusion about the appropriate target reserve margin after doing that analysis?

A. After doing all of our analyses, we felt that we should recommend a planning reserve margin target of 20 per cent.

Q. Why did you feel that was the appropriate number?

A. We felt that was appropriate, first of all, given our qualitative review of Hydro's characteristics, our experience and background in looking at planning reserve margins for a large number of utilities, we looked at the results of our calculations both in benchmarking and then varying the study assumptions for the loss of load probability on the Hydro system, and then when all that was done, with the justified reserve margins coming out in the 16 to 18 per cent range, we looked at what would be -- how big a jump would be involved in actually going from a 24 per cent reserve margin to something else.

Having a lot of background as a utility planning engineer, we tend to try to look at things somewhat more conservatively if we have an option. And going from a 24 to a 20 per cent reserve margin is a very substantial jump. Regardless of what the numbers showed, I probably wouldn't recommend going any further.

Q. Let me just return for a moment to the F&D model, you said you tried to run it and you couldn't get it to run. Do you have some comments on the F&D model in terms of its usefulness for planning purposes?

A. Yes, I do. First of all, F&D reflects an outage criteria which is different from that that we use in LOLP, LOLP looks at the probability of an occurrence of an outage, F&D is a loss of energy expectation type model and looks at how many megawatthours or kilowatthours might not be served given a particular reserve margin.

Conceptually I think it's a very attractive approach.

The use of outage costs to price out the energy that is lost also conceptually is attractive, although outage costs and the use of outage costs in reliability planning is still in a developing state.

From my perspective, you see a large amount of variety from utility to utility in terms of the levels of outage costs that are deemed appropriate for use in utility planning.

Q. Do you have any idea of what outage costs are used in American utilities that use that type of analysis?

A. Yes, I do, and it varies over a wide range. I have seen, well as recently as within the past month in studying reliability planning for Kentucky Utilities, a large utility down in Kentucky, they have used a range but in general they use outage cost numbers of around $1 per kilowatthour. But like I said, they do use a range somewhat because there is no accepted standard that I am aware of as to what level you set these outage costs at and how you really determine them. That's a problem. It's an area that is going to develop, however, I think, and as it develops I think the usefulness of planning approaches like the one that Hydro uses will increase.

Two other areas getting back to F&D, if I might for a minute, that I have some comment on. The first had to do with the apparent stability of the answers that we were seeing out of F&D.

When Hydro filed its Balance of Power,

they seemed to be saying that F&D was giving them -- they were using an outage criteria of 25 system-minutes as the basis for their 24 per cent reserve margin, but before we had completed discovery, this apparently had changed to 10 system-minutes, rather substantial change without any apparent effect on the resulting reserve margin. This certainly raised questions in our mind and really kind of peaked our interest, made us especially interested in trying to run the F&D model, and to see just how these results were working out.

That really gets me to my last comment on the F&D model. In trying to run it we, of course, had a great deal of difficulty. There seemed to be a lot of confusion initially, even on Ontario Hydro's part, as to whether or not we had been delivered every piece of the model. There was a considerable amount of back and forth between us and Hydro. As it turned out we never were able to get F&D to run the way Hydro was running it. This raises questions about the workability of the model and really the ability of parties other than Hydro to be able to use this thing and to be able to verify the results that Hydro is getting, and to look at the impact of some of our changed assumptions when run through F&D.

So, being used in a forum like this, you

would really hope that all of the parties would have access to this study approach and would be able to look at the effects of varying assumptions on the answers that you would get out of a model like F&D.

Q. Thank you. Mr. Lanzalotta, in doing your analysis what assumptions did you make about the availability of power from the Manitoba Purchase?

A. Actually, I made no assumptions at all. We did not include the Manitoba Purchase when we did our reliability study.

Q. If transmission from the Manitoba Purchase or if the transmission line was built, was available, what impact would this have on your assessment of the appropriate reserve margin?

A. I would think that building a high capacity transmission tie with Manitoba would tend to increase the inherent reliability on Hydro's system and might lead to a slight reduction in the target planning reserve margin.

Q. If I could move on now to talk about transmission related issues. Can you tell us, tell the Board, what CEG asked you to do with respect to transmission issues?

A. Yes. We were asked to look at transmission in the context of Ontario Hydro's system

planning, to see what consideration was being given, and to see whether or not transmission considerations were being adequately factored into capacity supply planning.

Q. I understand you asked a number of interrogatories of Hydro concerning transmission. Can you just tell us about that and what type of responses you got?

A. Yes, we asked a substantial number of interrogatories on transmission. Hydro's initial response was that these questions weren't really relevant to the planning considerations that were being addressed in the Balance of Power.

Q. Can you just look at, in the second appendix, there is an interrogatory, 2.7.11, it's about two-thirds of the way through the binder.

THE CHAIRMAN: Which number, Mr. Starkman?

MR. STARKMAN: 2.7.11.

THE CHAIRMAN: Which appendix?

MR. STARKMAN: 746, Exhibit 746. I'm sorry these weren't tabbed.

THE CHAIRMAN: It's okay. As long as you give me the appendix number.

THE WITNESS: I think it is Appendix 11.

THE CHAIRMAN: Appendix 11. Thank you.

MR. STARKMAN: Yes.

Q. Now, Mr. Lanzalotta, is this an example of the type of interrogatory, the type of response that was received?

[9:35 a.m.]

A. Yes. As a matter of fact I believe the list of interrogatories to wit which were all referred to Hydro's response as included here is -- I guess I think we give the list right toward the end of this appendix.

You can see there are 20 to 25, maybe more, interrogatories to which Hydro referred us I think back to this response they gave to 2.7.11 where they simply say:

> This information requested has not been provided as these system delivery details are not relevant to the review of the Demand/Supply Plan application.

THE CHAIRMAN: Mr. Starkman, we should put 2.7.11 on the list for this panel.

THE REGISTRAR: That was prefiled and had 434.111. You want a new number.

THE CHAIRMAN: I want a number for this panel.

THE REGISTRAR: It will be 781.3.

---EXHIBIT NO. 781.3: Interrogatory No. 2.7.11.

MR. STARKMAN: Mr. Chairman, can that number also include all of the interrogatories that are listed.

THE CHAIRMAN: In Appendix 11?

MR. STARKMAN: In Appendix 11 because they were all questions with the same answer, the same initial answer.

THE CHAIRMAN: Right. Yes.

MR. STARKMAN: Q. Now, just to be complete on this, I understand that subsequently there was some further information forthcoming from Hydro in response to some of these questions?

A. That's correct.

I believe we provided some written justification for our requests and then we came to Toronto and met with Hydro and pretty much had to explain again why we wanted this stuff. And then some of the material that we had asked for was finally provided to us.

Q. In your opinion what is the relevance of transmission to system planning.

A. Transmission system planning is relevant in our context here because the availability

of transmission, the availability of unused capacity in the existing transmission system can have significant implications to the choice of the type and the location of additional resources which can be added to the system.

Also, the lack of available capacity in the existing system can have implications in the opposite direction in types of planning like this. For example, if a utility system has large amounts of unused inter-tie capability with neighbouring utilities, that utility can make a different assumption as to the amount of off-system assistance available when they set their generation planning target reserve margin.

Similarly if those ties are almost completely loaded, this also has an impact because if those ties are fully loaded you can't reasonably assume to get emergency import assistance over those ties. That is one facet of why I think the transmission considerations were relevant within this proceeding.

Q. Can you comment on the proper balance between supply and transmission planning?

A. I think you have to look at both of them together. You can't really tell much about one in the absence of looking at both.

Q. What conclusions have you been able to draw from your analysis of Hydro's transmission system and the degree of integration between supply and transmission planning?

A. Of course the information that we had access to was more limited than what we hoped. But the analyses that we were able to make indicates that Hydro's system seems adequate for serving, for delivering generation to the load under most first contingency situations but that there is not a lot of unused internal transmission on the Hydro system.

Q. Can you comment from your experience as to whether interruptions of service are caused by transmission failure or by the supply failure?

A. On Hydro's system like on the system of most North American utilities with which I am familiar, very, very few outages are ever caused by shortage of generation. Most interruptions of service result from transmission problems and problems further on down the line, distribution system and the like.

MR. STARKMAN: Thank you, Mr. Lanzalotta. I have no further questions.

THE CHAIRMAN: Who is the first to cross-examine? The Ontario government? Is the Ontario government here this morning?

MR. R. WATSON: I don't believe they are Mr. Chairman. Mr. Hamer has asked to go ahead of me and I have no objection to that.

MR. HAMER: I won't be very long at all.

THE CHAIRMAN: Right.

<u>CROSS-EXAMINATION BY MR. HAMER</u>:

Q. Mr. Lanzalotta, in the numerous papers which are at the back of your report, there is a memorandum which I don't think we need to turn up referring to a letter from Mr. Charles Komanoff of August 13 of 1991.

A. I recall that, yes.

Q. Are you familiar with that document?

A. I believe so, yes.

Q. And then there is another memorandum dated October 2 of 1991 which refers to degraded nuclear performance suggested by Komanoff. And I'm wondering if the suggestion as to nuclear performance is contained in that Charles Komanoff letter of August the 13th of 1991?

A. I thought that it was. Maybe we should take a look at it.

Q. I simply wanted to ask you for a copy of that August 13th of 1991 Komanoff memorandum. Do you have that here?

A. I don't believe I do but I am sure we can provide it. The mechanics of that were that I talked on the phone with Mr. Komanoff and because our timing at this point was really tight, he told me what he intended for me to do with the nuclear performance and then -- I hope he confirmed it in the letter. I assume the letter says what he told me to do but I don't have it with me. I know that we can make one available.

MR. D. POCH: Mr. Chairman, I don't have the exhibit number but Mr. Komanoff's study has been filed and that's -- it's 563.

MR. HAMER: Q. So is that the letter of August 13, 1991?

A. I don't believe that the letter is the entire study.

THE CHAIRMAN: Perhaps we should turn it up because I am a little confused by this conversation.

MR. HAMER: Yes, I'm sorry.

There is a mass of internal memoranda which are part of this witness' exhibits and I am looking at Exhibit 746, and this memorandum happens to be in front of a divider in my copy of this thing and it's about --

MR. STARKMAN: What appendix is it?

THE CHAIRMAN: There is an appendix at the front of each blue tab, if we can get that appendix number.

MR. HAMER: It's to Peter from Fred and it's dated September the 4th of 1991.

THE WITNESS: Okay. This is Fred Strauss that this is referring to. He was working under my direction. That is the Komanoff letter to which he refers. It was just confirmation from Mr. Komanoff to us that what he told us over the telephone was in fact what we were supposed to be doing with the nuclear performance indexes.

MR. HAMER: I wonder if I might ask Mr. Poch if he has a copy of the August 13, 1991 letter.

MR. STARKMAN: We don't have one with us. We will look and see if we can find it. If we find it, we will provide it to you.

MR. HAMER: And if CEG's lawyers aren't able to get it, you will get it for us, Mr. Lanzalotta, and provide me with a copy through CEG's lawyers.

THE WITNESS: That's correct.

MR. D. POCH: I think to be clear here. Without looking at the letter, I'm not sure if it's in the nature of a communication between these consultants with counsel or what have you but I certainly have no

problem in undertaking to provide the numerical assumptions which is what this turns on that were contained in the letter. I just want to put that caveat on it, if that's permissible to the Board.

THE CHAIRMAN: I think what Mr. Hamer wants is the letter; is that right?

MR. HAMER: Yes, Mr. Chairman.

THE CHAIRMAN: It's referred to in the material here; it probably should be produced if it's available. I have not idea what significance it has but....

MR. HAMER: Nor do I at this point.

Q. Will you provide that to me, Mr. Lanzalotta?

A. I would be happy to.

Q. I have forgotten what we do about undertakings. Do we number them.

THE CHAIRMAN: We number them, yes. This will be the first one.

THE REGISTRAR: The next exhibit number is 783; therefore, this will be undertaking 783.1.

---UNDERTAKING NO. 783.1: CEG to provide August 13, 1991 memorandum from Mr. Komanoff.

MR. HAMER: Q. Mr. Lanzalotta, when you had come to your conclusion about the 20 per cent

planning reserve margin or 16 per cent planning reserve margin depending on the assumptions one adopted, had you reviewed Mr. Marcus' work on reserve margins?

A. No, I hadn't at that point.

Q. Have you reviewed Mr. Marcus' work on reserve margins since that time?

A. I believe I may have taken a quick look through it. I haven't concentrated on it.

Q. In particular, you have taken a look at his report entitled "Comparing the Reliability and Resource Reserve Margins of Nuclear Generation to NUG in the Ontario Hydro System" which has been marked as Exhibit 739?

A. I believe I have read it once, yes.

Q. Did your reading of that document cause you to change your conclusions in any way?

A. No, it did not.

Q. Now at page 45 of your report being Exhibit 744--

A. Yes.

Q. --you say at the bottom of that page:

> In comparison to the documentation which Ontario Hydro was able to provide and the organization which Ontario Hydro was able to achieve for its LMSTM, its

F&D model was a shambles.
Is that correct?
A. Yes, sir.
Q. And may we take it from that statement that the documentation and the organization of the LMSTM were not a shambles?
A. It was very well organized and presented.
Q. And documented?
A. And documented.
Q. So that that model is a helpful tool in evaluating Ontario Hydro's planning analysis as presented in this hearing to date?
A. Oh, I haven't done very much analysis as to how the LMSTM model really is being used. I am familiar with the documentation because a copy of it was made available. But, as to how it's being used or the appropriateness of such use, such models in general are useful in these types of planning proceedings but I haven't really done enough in looking into the use of LMSTM to express an expert opinion on that here.
Q. But from what you do know about the organization and documentation of Ontario Hydro's LMSTM model, you wouldn't anticipate running into the kinds of problems that you ran into with the F&D model which

was a shambles in your view?

A. Let me just say that the documentation that we had for LMSTM was far superior to what Hydro was able to provide for F&D. It is entirely possible that we could have had better documentation on F&D and still had trouble, but I have no way of knowing. Not having more thorough or better organized documentation, it was more difficult for us on F&D however.

Q. So the answer to my question would be yes, from what you know about LMSTM in Hydro's hands, you wouldn't anticipate the same kind of problem that you had with F&D.

[9:50 a.m.]

A. I guess I could say that.

Q. Yes. Could we look to page 64 of your report, please. You discuss there the matter of transmission facilities and how - if I can summarize fairly but generally - NUG suppliers appear to be penalized in the way that Hydro takes account of transmission considerations in dealing with NUG suppliers; is that fair?

A. It appears that NUGs may be being placed under more constraints locationally than Hydro might place under its own facilities.

The intent here is simply to say that from my understanding of Hydro's process, when they select the type of generating unit they expect to be their next supply side addition, it's done so pretty much without a geographical constraint being put on the selection. To the extent that Hydro does not do this for its own units, it should not be doing this for the non-utility generators. That was pretty much the thrust of my discussion here I think.

Q. That's because the NUG facilities in your view, I take it, ought to be placed on a level playing field with Ontario Hydro facilities for planning purposes?

A. That's the thrust of my point, yes.

Q. All right. And similarly, you would agree that when Ontario Hydro is looking at possible additions is to its own facilities, they ought to be on a level playing field with NUG competitors; correct?

A. Yes, it's kind of hard for me to argue that. [Laughter.]

Q. I hope you will find that with most of my questions. [Laughter.]

When you say that you recommend a 20 per cent reserve margin for Ontario Hydro in place of the 24 per cent which they currently adopt, is it fair to

say that you have not calculated the 20 per cent reserve margin in the same manner that Ontario Hydro has calculated its 24 per cent?

A. That's correct.

Q. Is it also fair to say that the rigour of your analysis was lessened by the difficulties you had in reproducing Ontario Hydro's F&D analysis?

A. I don't think I agree with that. I would say I used a different approach. However, even the material which we have been included here indicates that we made something like 45 to 50 passes of the model, studying various characteristics of the Hydro system.

Q. Which model is that?

A. The LOLP model.

So we would have been more rigorous had we been able to run both F&D and LOLP. But I think we prosecuted our LOLP analysis with all the rigour that was required to reach an opinion.

Q. But you will agree with me that your results are not directly comparable to Hydro's results because your approach was a different one using a different model?

A. Well, I don't know. I can't say that

my results aren't comparable. We have shown through our benchmark that -- and at least certain types of system operating characteristics, we get results out of our model that don't appear all that much different from some of the results that Hydro gets when it models its system.

Now, it's a completely different approach to determining the reserve margin, but the approach that we have used has been used rather widely, even by Hydro in its past, and it gives a traditional approach.

Not comparable, the methods are not comparable but the results, I think the result are relevant and comparable to an extent.

Q. Will you agree with me this far, that your preference was to do what you attempted to do first, which was to come up with an analysis using the F&D model?

A. Yes, sir. And that's because there would be a lot less question and quibbling over which modelling approach, which type of reliability index is most appropriate. I wanted to try to present our analysis on the same basis that Hydro had used to make theirs.

Q. And you told Mr. Starkman that you did not include the effects of the Manitoba Purchase in

your analysis and I didn't hear you tell Mr. Starkman why not.

A. We were modelling a representation of the Hydro system, first of all we were using 1989 hourly loads, and I guess we were looking at those generating units that might reasonably have been available in that time period.

Other than that, no particular reason. We definitely weren't ordered to do it one way or another; it is just the way we chose to do it.

MR. HAMER: Thank you, those are my questions. I am very much obliged.

THE WITNESS: Thank you.

THE CHAIRMAN: Mr. Watson, are you next?

MR. R. WATSON: Yes. Thank you, Mr. Chairman.

CROSS-EXAMINATION BY MR. R. WATSON:

Q. Mr. Lanzalotta, on page 2 of your report we have your Executive Summary, and as you have discussed with Mr. Starkman, you recommend a 20 per cent planning reserve margin or 16 per cent, depending on which nuclear outage rates you used.

A. I don't think I make a recommendation of 16 per cent, or at least I don't mean to. I don't think I made a particular recommendation other than

just the 20 per cent. I don't mean for this to be interpreted as saying I think Hydro should use a 16 per cent planning reserve margin.

Q. Thank you. Now, as you discussed with Mr. Starkman, one of your primary assumptions was the increase in the inter-tie assistance from 700 megawatts to 3,200 megawatts; is that correct?

A. That's correct.

Q. Is it fair to say from your analysis that if you do not make that assumption of 3,200 megawatts and instead you use Hydro's number of 700 megawatts, that your analysis suggests a planning reserve margin of about 26, 27 per cent?

A. That's correct.

Q. Just a few minutes ago you were talking about the Manitoba Purchase with Mr. Hamer, and you indicated that you used 1989 hourly loads.

A. Yes.

Q. Do I understand from your evidence that, in effect, your benchmark year was 1989?

A. No. The benchmark results that we were tying to were probably calculated by Hydro in years other than 1989. The 1989 loads were used simply because those were the only hourly loads that were available to us, from what I remember.

Q. So when you did your LOLP analysis you used 1989 hourly loads?

A. That's correct.

Q. And no doubt, Mr. Lanzalotta, you are familiar with the Panel 2 evidence that Hydro put forward that indicated that 1989 was a bad year.

A. A bad year in what respect?

Q. In a reliability sense: Outages, public appeals, voltage reductions.

A. Not particularly familiar, but I could take that subject to check.

Q. Yes, Mr. Lanzalotta, what you might want to check is Volume 17 of the transcript, I believe it's around page 3000. I could get the exact page reference for you.

A. Yes. It seems that if '89 were a particularly bad year, then that would provide a particularly stringent test for any reliability index that would be applied against those loads.

Q. Okay. Mr. Lanzalotta, talking about the methodology that you used, the LOLP methodology, that specifies a criterion of 1 in 10 years?

A. That's correct.

Q. And you would agree with me that this target of 1 in 10 is fairly arbitrarily; it's simply a

convention that utilities use.

A. It's a convention that utilities have used for a number of years and have been in widespread use. Arbitrary in the sense that it has produced results from system planning that utilities have felt fairly comfortable with.

Q. Right. Utilities have managed to steer clear of major problems using this value, but there is no deeper basis for the number other than that, is there?

A. I think it goes a little bit deeper than that.

There are two elements to the setting of a reliability criterion, one is that it provides a level of service reliability that the utility and its customers can live with, and two, are the cost implications. It should not produce and exorbitant cost for producing this reliability.

If either of these two facets for what you call an arbitrary selection on the basis of LOLP were producing a significant problem, then I would have expected them to pick a different number than one day in 10 years.

For example, I think I mentioned the Hawaiian Islands Utilities, they picked a number one

day, I think, in four-and-a-half years, which not as stringent a criterion, but I believe in their case cost becomes a factor because they are completely uninterconnected; they are an island in the middle of the ocean, and to go for a one day in 10 year for them would be prohibitively expensive. So I don't agree that its completely arbitrary.

Q. I guess, Mr. Lanzalotta, the essence of what you are saying was your words, you pick a different number. The essence is you pick a number and that number manages to keep you out of difficulty and it is not a number that's based on any analysis. Historically it's kept you out of trouble and that's the basis for the number.

A. Well, that's a form of analysis in and of itself, I would think.

Q. Okay. Also dealing with LOLP, it's fair to say there is some ambiguity about the definition; isn't that fair?

A. I'm not sure I follow.

Q. You would agree with me that some utilities use an hourly basis, some use a daily basis?

A. There is different ways to calculate what is called LOLP, yes.

Q. In fact, didn't you want to start

using an hourly basis and you ended up using a daily basis?

A. We looked at the calculation on both bases. But you are right, we ended up using peak load from every day.

Q. Not only can you look at those differences, but you can look at, for instance, adverse conditions from any of the input assumptions versus median conditions for some of the input assumptions?

A. Yes, that's correct.

Q. So you would agree with me then, Mr. Lanzalotta, that LOLP can mean different things for different utilities?

A. Different utilities can choose different approaches for calculating LOLP, yes.

Q. Mr. Lanzalotta, if you could turn with me to page 12 of your evidence. If you refer to the second paragraph, with the words "before looking at." Do you have that?

A. Yes, I do.

Q. The second sentence reads:

> It is double counting reserve requirements to add reserve requirements attributed to load forecast uncertainty or other uncertainties to reserve margin

requirements based on traditional
reliability criterion.

You continue:

The reserve margin has historically been used to safeguard the reliability electric service against higher than expected loads and lower than expected (resource) levels. Hydro tries to justify its planning reserve margin by looking at load forecast uncertainty, generating unit construction completion uncertainty, and various other factors separately from the base planning reserve margin, and then by adding an increment to a base reserve margin to account for these factors.

Now, if I could go back to the first of those statements, please, Mr. Lanzalotta. At the end of that statement where you are talking about double counting, you are referring to traditional reliability criteria; is that fair?

A. Yes.

Q. And LOLP is one of those traditional reserve reliability criteria?

A. Yes.

Q. You would agree with me that F&D would not fit into that category?

A. Yes.

Q. Now, looking at the third sentence I referred to, Hydro tries to justify its planning reserve marriage by looking at various uncertainties, and you say, then adding an increment to a base reserve margin to account for these factors.

You are, at that point, trying to explain what Hydro does, and as I understand it, is it fair to say that you are referring to table 6.10 in Exhibit 87? That's at page 114. Is that the basis for that statement, Mr. Lanzalotta?

A. I don't know if I tied it solely to this table, but it was this type of approach I believe that I was referring to.

Q. This type of approach that we see on table 6.10?

A. Yes.

Q. Now, isn't it fair to say that this type of approach at 6.10 is not Hydro's primary approach and primary method for calculating reserve margin?

A. That's correct.

Q. Their primary method for calculating

reserve margin is the F&D model?

A. That's right. This is done primarily to establish the reasonableness of the number that Hydro gets out of F&D.

Q. This analysis in chapter 6 of Exhibit 87 is, in effect, a back of the envelope check on their F&D model.

A. That's one way to describe it, yes.

Q. When you look at that analysis, at table 6.10, the number that they start with, No. 17, 17 per cent under the heading for the use of emergency measures?

A. Yes.

Q. Now, that isn't a number that is derived using traditional reliability criteria.

A. I'm sorry, that isn't?

Q. That is not a number that is derived using traditional reliability criteria.

A. I forget exactly how they derived it.

Q. Perhaps could you turn to page 100, Mr. Lanzalotta. Table 6.1 we have the actual reserve margins between 1985 and 1989, you will notice the smallest of those figures is in 1986, 17 per cent.

A. Yes.

Q. And isn't 17 per cent that's used in

table 6.10 just the lowest actual value of Hydro's reserve margin they have experienced?

A. Yes. In other words, it is not traditionally derived.

Q. Right.

A. Right.

Q. And just finishing up on the differences between the two. LOLP is traditional as you indicate and it, if you will, implicitly hedges against uncertainties such as load forecast, whereas F&D explicitly recognizes those uncertainties as inputs to the model; isn't that fair?

[10:13 a.m.]

A. Yes.

Q. So your statement where you are saying that Hydro tries to justify its planning reserve margin and you go on talking about uncertainties and then those uncertainties being added to the base reserve margin, that criticism is not valid for the F&D model but it is valid for the -- or you are saying it applies to the analysis, the secondary analysis we see at table 6.10?

A. Yes, sir.

Q. Mr. Lanzalotta, if you can turn with me to page 16. You refer to the Pacific Gas and

Electric reliability reserve margin. You say it could be as low -- or historically has been as low as 12 per cent.

That 12 per cent figure is a short-term figure, it's not a long-term figure, and that's not comparable to Hydro's target reserve margin that we have been discussing here; isn't that fair?

A. Well, it certainly hasn't been as long lasting as Hydro's use of the 24 per cent. Pacific Gas and Electric has in recent years shown a tendency to change its planning reserve margin almost on a yearly basis in response to particular system operating conditions. So, from that viewpoint it seems to jump around quite a bit. It would be difficult to compare it to some extent perhaps with Hydro's 24 per cent which it has used over a longer period.

Q. Just to focus in, Mr. Lanzalotta. My question is: The 12 per cent figure that you are referring to on page 16 is not a figure that is directly comparable to the 24 per cent reserve margin that Hydro uses?

A. I thought within the context with which this 12 per cent was presented that it was their planning reserve margin target. It's just that as the characteristics of their system has changed they have

changed their planning target.

Q. Now, Mr. Lanzalotta, can you tell me what year or years PG&E used this 12 per cent value as their target reserve margin?

A. I'm not --

Q. In the same sense that Hydro was using a 24 per cent?

A. I'm not sure that I could. I don't remember the year.

Q. Okay. Could you get that for me please, sir.

THE CHAIRMAN: That will be an undertaking.

MR. WATSON: Please, sir.

THE CHAIRMAN: Number?

THE REGISTRAR: 783.2.

THE CHAIRMAN: Thank you.

---UNDERTAKING NO. 783.2: CEG to provide year or years PG&E used 12 per cent value as their target reserve margin.

MR. R. WATSON: Q. Mr. Lanzalotta, you were discussing inter-ties with Mr. Starkman. I believe your evidence on inter-ties is in Section 4.4 starting at page 24 and going through to page 32?

A. Yes, sir.

Q. You are talking about 3,200 megawatts

of transmission capability and I assumed that you have no difficulty with the concept that discussing transmission capability is meaningless unless there is at least that much generating capacity available in the adjoining regions when Hydro needs it?

A. That's correct.

Q. Now, in looking at the -- and in fairness to you, sir, you not only look at the inter-ties you then in the pages that I have quoted in Section 4.4 start to go through some of these generating capacities that you say may be available and I would like to take a minute and look at some of those.

One of the issues you deal with is seasonal diversity and that is on page 30 of your evidence. If you could turn with me briefly to that page.

A. I'm there.

Q. You will see at the top of the page, the first sentence begins:

> Utilities in the ECAR region showed a 1991 winter peak load which was 5,255 megawatts less than its 1991 summer peak load while New York utilities had a 1991 winter peak load which was 2,700

megawatts less than their 1991 summer peak load. These numbers indicate that some 7,955 megawatts of potential generation is available to Ontario Hydro's tie lines during Ontario Hydro's winter peak load period simply by virtue of the seasonal diversity between Ontario Hydro and the utilities to the south.

Now, just dealing with seasonal diversity and we will get to other issues later but just dealing with seasonal diversity, what you have done is you have looked at two areas: ECAR and New York. You have calculated the difference between the winter peak and the summer peak in each one of those; is that fair?

A. That's fair.

Q. And then you have taken those two differences and added them together to get your number 7,955 megawatts?

A. That's correct.

Q. So that number simply represents the difference between winter peak and summer peak in those two utilities?

A. That's correct.

Q. In order for that, in order for all of that 7,955 megawatts to be available, you must make

the assumption that all of the generation that is available in the winter is also available in the summer; isn't that correct?

A. That's correct.

Q. Isn't it fair to say, sir, that a number of utilities tend to do maintenance in off-peak seasons; for instance, if they winter peak, sometimes they do maintenance in their summertime and vice versa?

A. That is correct.

Q. And as a result of that, some of the 7,955 megawatts that you say are available would not be available because of this particular phenomenon?

A. That's correct. Although let me explain a little bit. It would not all be immediately available but some of the capacity that is under maintenance perhaps could be made available if there were some notice.

For example, we have talked earlier about how the spinning reserve would be used to immediately pick up the needs in the case of an emergency on the system. That gives the utilities involved a little bit of time to start perhaps changing resource assignments, perhaps decide to defer maintenance, try to bring something back on-line that had been out for maintenance. Make other moves.

Now, this is not always going to be possible with generating units that are out for maintenance. If you take a big coal-fired steam unit out for maintenance and you are one week into a four week planned overhaul, it's pretty difficult to envision pulling all the pieces back together and trying to get that unit on-line.

But if the unit hasn't actually been taken off-line yet or it's about to be taken off-line, then there is an opportunity to perhaps make this available where in the absence of the emergency it would not be available as you suggest.

So, I don't mean this to read that this roughly 8,000 megawatts is always going to be available. It merely indicates the potential availability of off-season capacity assistance.

Q. Mr. Lanzalotta, you have mentioned one potential problem with the units being off-line. You mentioned the coal plant. I don't intend to take you through many of the other instances which could occur.

Is it fair to say that in coming up with this 8,000 figure, what we see on page 30 is the only analysis you did of seasonal diversity? You have not done any other analysis to give us any sort of figure

which you would say is a firm figure for available resources?

A. That's correct.

Q. Now, further down page 30, Mr. Lanzalotta, near the bottom of the page, the second last line, we have now, as I understand your evidence, switched topics. You were talking about seasonal diversity and you are now talking about reserves; is that fair?.

A. Correct.

Q. All of this is still with respect to, in effect, trying to get the generation to support the 3,200 megawatts of inter-tie assistance.

A. Yes, sir.

Q. So dealing with this reserve question down at the bottom of page 30, you say:

> Taking a total of ECAR and New York spinning and quick start reserves at the 1991 winter peak produces 5,551 megawatts of operating reserve.

If you could continue down page 31, the fourth last line, if you have that, sir, beginning with the word "Between...."

A. "Between these two regions..."?

Q. Yes.

A. Yes, sir.

Q. Between these two regions the available quick start reserves, mostly spinning reserves, which were tied to Ontario Hydro's interconnections to the south increased by some 428 megawatts. This figure suggests that if Ontario Hydro's value of 700 megawatts was a reasonable assumption for the assistance available through their transmission interconnection in 1981, then a substantially larger figure would be appropriate now.

Sir, if you could look at Exhibit 745, which contains Appendices 1 through 9, and turn to Appendix 4.

A. I have it.

Q. The pages aren't numbered, sir, but if you would look at the fifth page, at the top of the page there is a typewritten No. 4. And the first line is 3.6, Sustainability of Reserve.

A. Yes.

Q. Do you have that, sir?

A. Yes.

Q. Sir, you would agree with me that

this is the NPCC operating reserve policy?

A. Yes.

Q. Ontario Hydro belongs to the NPCC?

A. Yes, I believe they do.

Q. There is no doubt in your mind about that?

A. No.

Q. If you would look at page 4 of that operating policy, there is a heading 4.0, Procedures, then 4.2, Daily Operation?

A. Yes.

Q. If you could just follow along with me. 4.2.1 says:

> Energy associated with operating reserve may be interchanged as economy energy with the understanding, that is, it is immediately recallable and the buyer must therefore have the capability to support the withdrawal of this energy in addition to meeting its operating reserve requirements.

And then continuing on to 4.2.2:

> When an area foresees it will be unable to provide its 30 minute reserve requirements with available resources

because of forecast load errors, forced outages or other limitations, it shall obtain capacity from outside the area if the short fall is foreseen more than 4 hours in advance or if the short fall is expected to persist for more than four hours. Such capacity shall not be from another area's operating reserve.

I would suggest to you, sir, that this makes it reasonably clear that utilities can't count on other utilities' operating reserves; isn't that fair?

A. I don't read this that way at all.

Q. No?

A. No. Let's talk about economy energy which 4.2.1 addresses.

Q. Right.

A. What happens in economy energy between two utilities? Say I'm utility A and you are utility B and I've got a thousand megawatts of spinning reserve from which I'm going to make an economy sale to you.

What this says is that you may be buying the 1,000 megawatts from me but you have 1,000 megawatts of generating capacity which is in essence spinning and ready to pick up that load. The only

thing I am providing you with in an economy energy sale are cheaper kilowatthours, on usually a fuel price basis, than what you are able to supply from these units yourself.

But all of the capacity -- this is not a capacity sale. The capacity is still available to my system virtually on a moment's notice. So, I don't think these economy transactions have any effect at all on the reserve capacity that can be deemed available from NPCC.

Q. Dealing with the reserve with the economy energy, doesn't the guideline go on to say the buyer must have the capability to support the withdrawal of that energy in addition to meeting its operating reserve requirements?

A. What that means is that if I am selling to you economy energy, you have the capacity to supply that energy yourself and it's available to you right now in addition to supplying whatever reserve requirements your utility has. So, my ability to supply these reserves is not affected by my making the economy sale to you.

Q. In 4.2.2, when you are talking about the precedent paragraph, you are talking about economy energy?

A. Right.

Q. This paragraph deals with 30 minute reserve requirements?

A. That's right.

And what it says is that say I have a short-term reserve requirement of 1,000 megawatts, and I'm going to buy that from you because I'm tight on capacity myself, essentially this says that I can do that but that you have to provide your own reserve requirements completely in addition to the reserve requirements you are agreeing to supply for me. This just reinforces in my own mind that those reserves are going to be there when they are needed.

Q. Doesn't the statement say, sir, that the capacity that we are talking shall not be from that area's operating reserve?

A. That is saying that if I am buying reserves from you and you are selling reserves to me, you are not making those reserve sales out of the capacity that you are maintaining on your system for reserves.

Q. That's right. And if New York and NPCC are providing power to Ontario Hydro, that can't be out of that area's operating reserve. Isn't that what it says?

A. If Hydro goes to NPCC and says, I don't have enough capacity to provide spinning reserve, I would like to buy some from you, then that sale is not made out of NPCC's reserves.

But if a big generating unit on the Ontario Hydro system goes down and the frequency on Hydro's system starts to droop, there will be an inrush of reserves from NPCC out of their spinning reserve unless the draw is so heavy that it threatens the stability on both systems in which case then the tie would be broken.

But, no, this does not in any way affect the assumptions that I have made regarding the emergency assistance available. This paragraph gives me even more certainty that those reserves are going to be there in the time of need either on NPCC's system or on Ontario Hydro's system?

Q. But, sir, as I understand spinning reserves, they are set up as, if you will, a safety factor for a utility?

A. That's correct.

Q. Is that a simple way of looking at them?

A. That's correct.

Q. And if those spinning reserves are

made available from New York to Ontario, then they are no longer available in New York for New York's safety factor. Isn't that fair?

A. No, that's not. I am not saying in my analysis here that Hydro is not going to provide its own spinning reserves. They are going to provide whatever spinning reserves the operating criteria calls for on the Hydro system.

But the reason the utilities interconnect in the first place and the reason they have emergency assistance operating agreements is so that these reserves will be made available across these utility interfaces when they are needed to the extent that the utility on the other side is able to supply them.

Now this is not contractual where Hydro says, I can't provide my own spinning reserves, I'm going to buy them from New York; that is not the situation we are talking about at all. Each side is providing their own spinning reserves but yet when there is a problem on one side of the tie or the other, the utility on the other side allows those reserves to come into play to the extent that they can to keep the system from collapsing.

Q. You would agree with -- I mean it is the simple principle of physics, sir, that if an object

is in one place it can't be in another place at the same time; isn't that fair?

A. That's correct.

Q. So if a utility has a certain spinning reserve and its spinning reserve is for its particular purposes and another utility requires assistance, and those spinning reserves are taken from the first utility, then that first utility no longer has spinning reserves it requires?

[10:30 a.m.]

A. What you are talking about now is trying to operate your system to protect against a double contingency. Utility systems in North America are inherently designed on a single contingency basis.

Neither NPCC nor Ontario Hydro operates its system assuming that NPCC is going to have a catastrophic event at exactly the same time that Ontario Hydro is. Utility systems could design and operate against that effect, but in general they operate against a single contingency criteria.

Now once Ontario Hydro experiences an event which causes it to make use of the reserves at NPCC, then at that point those reserves are no longer available to NPCC, but at that point both Hydro and the utilities in NPCC will take further action to shore up

the reserves, make additional capacity available and otherwise try to put themselves in a position so that there are enough reserves to try to survive the next event.

Q. Mr. Lanzalotta, I guess we will just agree to disagree on this issue. But let me leave it with this question. In the same way that you haven't done an analysis with respect to seasonal diversity, you have not done an analysis with respect to the reserves. You have simply, in effect, seen what is out there, you haven't looked or done any analysis as to what would be available under what conditions?

A. Well, I have investigated the operating criteria for these reliability regions. It says what the utilities plan to make available and the procedures that they expect to follow if they cannot make these reserves available from their own system. Beyond that, I have made no further analysis.

Q. Mr. Lanzalotta, on page 31 you refer to a figure of 428 megawatts of quick start reserves, and as I understand it, that's the difference between what was available in '81 and what was available in '91; isn't that fair?

A. That's correct.

Q. Isn't it fair to say, though, that

this 428 figure represents capacity that was built to meet demand growth down in the United States?

A. It's capacity built to provide reliable service on the utilities located in the United States. But at any one point in time not every megawatt installed on their system is needed, just as the same situation exists on Ontario Hydro's system.

Q. It's fair to say, though, that this is relatively short term in that long term these utilities are forecasting that this 428 megawatts will be eaten up by demand growth.

A. As demands grow, additional capacity will be installed also.

This was intended point out that if we believed that 700 megawatts was available, was appropriate for the Ontario Hydro system in 1981, then there is reason to believe that even more outside assistance would be available today. That was the thrust of the point that I was trying to make here, nothing more.

Q. Mr. Lanzalotta, if you could turn with me to page 38. On that page you are talking about the outage costs as part of your Section 7.2. And the second full paragraph begins with the words, "In the above approach." Are you with me, sir?

A. Yes.

Q. You indicate that:

In the above approach a dollar's worth of outage costs carries the same weight as a dollar's worth of power supply costs, but at $5.91 per kilowatthour, Hydro's customer outage rate is many times than virtually any rationale customer would consider paying for electric power.

Then you give an example of a typical combined-cycle generating unit with an installed cost of $750 per kilowatt, an operating cost of 2.5 cents per kilowatthour, and you indicate that under a typical set of capital recovery ratemaking assumptions the generation would cost 4.81 cents per kilowatthour. And you then go on to calculate the installed cost and you indicate that that would be $190,000 per kilowatthour.

If I could just deal with that for a minute. It's fair to say that there are two concepts that are at play here, one is outage costs and the other is power supply costs?

A. Yes.

Q. And if I could take you to an old expression, sir, for want of a nail the battle was

lost.

A. I'm familiar with it.

Q. Would it be fair to say that the 4.81 cents per kilowatthour represents the price of the nail under ordinary circumstances?

A. Okay.

Q. The $5.91 per kilowatthour represents the cost of losing the battle.

A. It's an interesting analogy.

Q. And I am suggesting to you, sir, that that might be one way of looking at the difference between the two, and I would ask you to accept that.

A. The problem that I have philosophically with these outage costs is that these are being represented as - the way I read it anyway - as what these customers would be willing to pay for a kilowatthour of electricity when it's not available.

Now, if customers were willing to pay $6 a kilowatthour, and electricity really had that marginal value to them, then I question -- and don't forget, we have different classes of customers now, each with radically different outage costs. And supposedly that reflects radically different marginal value of electricity to these classes.

If a class really is willing to pay $6 a

kilowatthour, then I just don't understand why it would not provide its own backup, rather than depending upon the utility to incur substantially higher capacity supply costs to provide that level of reliability.

Q. Now, sir, you are talking about the outage costs and you are saying that is the value that a customer would be prepared to pay for electricity under exceptional circumstances.

A. It appears to me that's the way it's being presented.

Q. Now, if I could give you another example. Consider a large paper mill has a lot of electricity motors, electric motors, it takes a while to have this plant loaded and ready to go. If an interruption in electricity occurs all the motors stop, the batch is lost that is currently in the mill, and that batch has a certain cost. That customer suffers a loss because of the outage that occurred.

A. That's correct.

Q. Isn't what we are looking at here in outage costs, the loss that that customer estimates that they would have from that interruption?

A. I can see that.

Q. Now, when you did your calculation and arrived at a figure of $190,000 per kilowatt, what

capacity factor did you use. How did you get that number?

A. First of all, we would have to look up above where I go from the $750 per KW to the 25 mills, or the 2.5f cents per KWH. I believe I assumed, I don't know, something like a 60 or 70 per cent capacity factor when I did that.

Anyway, I took the mathematical mechanics that I used to arrive at that and I worked backwards using the same capacity factor, I would assume something 60 or 70 per cent, to get to the $190,000 per KW.

Q. Okay, sir, so your analysis is based on a typical combined-cycle generating unit, and I think it is fair to say that that could have a capacity factor of 60 per cent.

A. Yes, sir.

Q. So at that capacity factor of 60 per cent, it would produce or could produce the electricity at the price that you calculate there, 4.81 cents per kilowatthour?

A. Yes, sir.

Q. Now, to get your value of $190,000 per kilowatthour, you have to assume the same capacity factor for the outage costs that you did for the price

of electricity?

A. That's correct.

Q. And, sir, I would suggest to you that a 60, 70 per cent capacity factor is simply not an appropriate basis for comparing outage costs with electricity prices.

A. You are saying that the capacity that you save in reserve in the case of emergency wouldn't operate at that capacity factor, I guess. I don't know, maybe I should hear the question again just to be sure.

Q. Sir, what I am suggesting to you is all along we have been talking about the dichotomy between the price of electricity and outage costs. And it is one thing to calculate the price of electricity at the capacity factor of your combined-cycle station, which for argument sake we will say is 60 per cent, the proposition I am putting to you, it's a completely different thing to calculate outage costs at a 60 per cent capacity factor.

A. Well, you have to remember how we are using these outage costs. I don't necessarily agree with your statement. Let me start by saying that.

The process that is being used here, these outage costs at $5.91 a kilowatthour are being

put on to a graph right along with the kilowatthours that are being produced by additional capacity or 4, 5, 6, cents per kilowatthour until an overall, minimum cost is reached. They are being put in right together as if they are the same thing. So there are ways of looking at this that, it looks like they are being used as if they are on a comparable basis.

Hydro is deciding to install additional capacity based on the fact that to some extent it may be better to avoid the $6 per kilowatthour and put in additional capacity.

So these things are being used right on the same table together. I can't say that there is absolutely no connection between them. They are very connected.

Q. I didn't say they weren't connected, sir. I was simply saying assuming a 60 per cent capacity factor for outage costs just isn't reasonable. A more reasonable factor is using something like the LOLP numbers that you were looking at.

A. I guess that's possible.

MR. R. WATSON: Mr. Chairman, I am about to move on to another area. I am close to being finished. I would imagine another ten minutes. I understand the morning break is usually taken now.

I am in your hands.

THE CHAIRMAN: Usually being we have only had two days. [Laughter.] But once you do something twice you establish a precedent, a tradition, I should say. We will break now for 15 minutes.

MR. R. WATSON: Thank you.

MR. REGISTRAR: Please come to order. This hearing will recess for 15 minutes.

---Recess at 10:46 a.m.

---On resuming at 11:01 a.m.

THE REGISTRAR: Please come to order. This hearing is again in session. Please be seated.

THE CHAIRMAN: Mr. Watson?

MR. R. WATSON: Thank you, Mr. Chairman.

Q. Mr. Lanzalotta, if you would turn with me to page 41 of your evidence.

A. Yes, sir.

Q. We are still talking about outage costs, and what you have produced there is table 3, which is outage cost per kilowatthour for certain sectors; is that fair?

A. Yes, sir.

Q. And that reflects the data that Hydro used in the early 80s?

A. That's my understanding, yes.

Q. And that would have been data that they used for their methodology which is commonly referred to as a value of service methodology?

A. Yes, sir.

Q. And you would agree with me that value of service methodology was a relatively new or at its infancy in the early 80s?

A. Yes, I would.

Q. On the next page, page 42, you have table 4, which is further outage costs per kilowatthours, using again certain society sectors, only these values are for the early 1990s, about a decade later.

A. Yes, sir.

Q. And you would agree with me that value of service methodology has progressed since its infancy in the early 80s?

A. It's had a lot more experience with it, yes.

Q. Part of that experience would have to do with estimating outage costs?

A. I would assume so.

Q. Just before we leave that point of outage costs, sir, would you agree with me that the target reserve margin in any effect is not particularly

sensitive to the estimated uncertainty in the more recent estimates of these outage costs?

A. I can see where it would not be, but I really didn't do any specific analysis one way or another.

Q. Okay. Sir, if you could turn with me to page 44 of your evidence. That's part of your Section 7.3 which you entitled "The Stability of Answers." The fourth line down you have a sentence that starts:

> It is difficult to have confidence in Ontario Hydro's reliability criterion or its reserve margin target given the substantial changes applied to its reliability criterion and the apparent failure of these changes to have any effect whatsoever on the target reserve margin.

Sir, as I understand that sentence, you are referring to the change that Hydro made in its system-minutes from 25 to 10, in the 1991 reliability review which has been filed at this Board as Exhibit 87.

A. Yes, sir.

Q. Sir, you would agree with me that

when your sentence refers to reliability criterion, that system-minutes is not Hydro's fundamental reliability criterion; is it?

A. It's one facet of their reliability criterion. I guess the most appropriate way to describe what they are doing is, as you did earlier, value of service.

Q. Isn't it fair to say that the fundamental criterion used by Hydro is, if you will, the economic criterion of balancing the marginal cost and benefit of additional reserve capacity?

A. Yes, sir.

Q. And we see the graphic example of that in figures 5.1, 5.2 and 5.3 in Exhibit 87, and that's starting at page 99 of Exhibit 87.

A. Could I have those figures again?

Q. 5.1, 5.2, and 5.3.

A. Yes.

Q. Those figures are the output of Hydro's F&D model. They are the ones that produce the reserve margin; isn't that fair?

A. Yes, I believe that's correct.

Q. If you will, system-minutes is a secondary indicator to the primary indicator that we have just looked at, those figures and those reserve

margins that those figures give us?

A. I think I could agree with that.

Q. And lastly, sir, if you could turn with me to page 65.

THE CHAIRMAN: This is Exhibit 744?

MR. R. WATSON: That's correct, sir.

Q. At the bottom of the page you have footnote 34, which refers to your Interrogatory 2.14.3, and you indicate that for the Bruce complex economic generation was lost during 350 days in 1988, 315 days in '89, and 342 days in 1990.

Now, sir, isn't it fair to say that the curtailment of generation from Bruce, which you refer to there, occurred during off-peak hours?

[11:13 a.m.]

A. It's possible. I did not examine whether it on peak or off peak but that's entirely possible.

Q. So if it did occur in off-peak hours -- sorry, let me start over again. If it did not occur during on-peak hours, then this would not have the same effect on reliability analysis as if it occurred during the other period; isn't that fair?

A. Yes. Although the thrust of this statement here, when we are talking about economic

generation, we are not necessarily talking about reliability as much as we are talking about the ability of the investment in this nuclear facility being allowed to produce all the benefits that it's capable of producing; that being the relatively low cost, low fuel cost of generation which you usually expect from nuclear.

But you are correct, we wouldn't expect those to have as much of a reliability effect as say an economic effect.

Q. Sure. I take your point, Mr. Lanzalotta. But just dealing with the reliability analysis, the most important time for system reliability is the on-peak hours?

A. Yes, sir.

MR. R. WATSON: Thank you, Mr. Chairman. Those are my questions.

THE CHAIRMAN: Mr. Rodger, are you next?

MR. RODGER: Yes.

THE REGISTRAR: Do you want that interrogatory, Mr. Chairman, 2.14.3 given a number?

THE CHAIRMAN: Yes.

THE REGISTRAR: 781.4.

---EXHIBIT NO. 781.4: Interrogatory No. 2.14.3.

THE CHAIRMAN: Mr. Watson referred to it

as CEG's interrogatory. It actually was an IPPSO interrogatory.

MR. RODGER: Thank you, Mr. Chairman.

CROSS-EXAMINATION BY MR. RODGER:

Q. Sir, I wonder if you could first turn to page 42 of your Exhibit 744.

A. Yes, sir.

Q. And there is one sentence on that page I would like to ask you about. This is a discussion that you are going through regarding the customer outage costs. In the bottom paragraph, the second last sentence you state:

> Large users are estimated to have outage costs of $6.32 per kilowatthour but large users are typically the quickest to reduce electric purchases in response to increasing prices.

Could you describe for me the evidence or the rationale that led you to that conclusion.

A. About the large users typically being the quickest to reduce purchases?

Q. Yes.

A. It's been my experience in my 20 or so years of consulting that large users are extremely sensitive to the price of electricity. And when the

price of electricity does show movement, frequently they have the most options as well as the most motive in terms of increased costs to take other steps other than simply purchase electricity at an increasing cost from the supplier.

Q. What other steps would those be that are open to large users?

A. They might decide to install back-up generation or they might decide upon means by which they can control the amount of purchase they make, limit increases in the demand, that sort of thing.

Q. Now, are you aware, sir, of the price changes in electricity in this province over the past three years?

A. No, I'm not.

Q. If I told you that in the past three years large consumers in the industrial sector in this province faced significant increases in electricity prices, real prices of 30 per cent, approximately, based on your statement I take it you would expect large industries, large users, to substantially curtail their electricity purchases?

A. Not necessarily. It would depend on what level the prices were when they started out and what level they end up at. If the prices are low

enough, some of the options with which I'm familiar may still not be economic.

Q. So a 30 per cent increase, would that be significant enough to trigger your statement on page 42?

A. Again it depends essentially what level the prices end up at. If the large users experience this 30 per cent increase and end up at price of 25, 30 mills, it's still going to be a lower price than they could attempt to utilize say a back-up source at. So if the prices were that low, I still wouldn't expect to see as much of that type of movement than I would if the prices were higher.

Q. Now, I wonder if you could turn now to page 7, we are staying with Exhibit 744. And this is the first full paragraph I would like to refer to. The first sentence reads:

> In electric system reliability planning, one goal is to provide sufficient generating capacity to limit to certain definable levels service outages caused by a lack of generation.

I take it that that description, that goal, also applies to the LOLP modelling analysis. Would that be correct?

A. Yes, sir.
Q. The second sentence reads:
Another typical goal is to avoid spending any more on generating capacity than is necessary to limit service outages to these certain definable limits.
I take it as well that that's a goal of the LOLP modelling analysis?
A. Yes, sir.
Q. The rest of the paragraph reads:
These target levels of reliability attempt to reflect the balance between, one, the increased cost of additional generating capacity; and, two, the economic cost of the incremental outages which the additional generating capacity would allow the system to avoid. More than one method of determining these definable target levels of reliability is in use today.
Is it your position with your paper that the LOLP method of modelling is superior to Hydro's F&D analysis?
A. No, it is not. As a matter of fact,

we would, I think, have preferred to have been able to rerun F&D with our assumption analyses but we were unable to.

Q. But you were unable to do so because of the lack of information which you have testified to?

A. Yes.

Q. In what respect is the F&D analysis superior then to the LOLP?

A. The primary characteristic that caused us to want to run it in this case is that it was what Hydro was using. We wanted to avoid this controversy over 'my model is better than your model' type of thing. But in the case where we were unable to do that, we picked what we thought was the next best approach given the circumstances.

Q. As a utility planner can you point to any specific elements of the F&D model which would give you more comfort as a planner entering into this exercise regarding reserve margins and which are appropriate?

A. Well, like I said, the fact that it was what was being used by Hydro was the thing that in our eyes made it the most attractive for use in this case.

As the various elements of Hydro's

approach get developed, as these customer outage costs get more clearly defined and are defined industry-wide on the basis that everybody has more confidence in, I can see that the outage cost aspects of a value of service approach such as Hydro used would make it attractive.

As for now, there seems to be a lot of volatility in that element of the analysis. For purposes of this proceeding, though, it was the fact that it was the model in use that made it more attractive to us potentially and that was the one that we wanted to use here.

Q. Just so I understand some of the essential elements of the model you used, the LOLP model, it basically tells you whether or not you are going to be able to meet the load or not but it doesn't tell you by how much or how little the load will be met or overstated?

A. That's correct.

Q. Would I be correct when I say that the main difference between the two approaches, Hydro's approach and your model, is that the F&D model, it does explicitly incorporate the customer outage cost where the LOLP model doesn't do that?

A. The LOLP consideration of that is

much, much more implicit. Whereas, in Hydro's approach, those cost are explicitly considered, yes.

Q. Even within the F&D model, the customer cost of outages, it really doesn't incorporate the example that Mr. Watson gave of losing batches of production; it really looks at the cost to remedy the power outage, be it by back-up generation or what have you?

A. Oh, I'm not sure I could characterize those outage costs that way. I don't really know exactly what is reflected in those outage costs. I haven't studied that in any great detail.

Q. Now if you agreed with me earlier on that one of the goals of the LOLP model was to strike this balance between the customer cost of outages and having the right amount or the optimal amount of generation on the system. How can you achieve that with the LOLP model if that model does not take into account the cost of customer outages?

A. I said it didn't explicitly take it into account. The usage of LOLP planning by utilities would not have been in use as long as it was or in such widespread use if use of LOLP resulted in an unacceptable level of customer outages.

The fact that it has been in such wide

use for so long I think is implicit evidence that it has successfully reflected those concerns, at least up to this point in time.

Q. So would it be fair to say then that the implicit recognition of customer costs in the LOLP model, that's satisfactory for purposes of your analysis of establishing appropriate reserve margin levels?

A. I think it provides an interesting comparison and a basis from which to judge the number that Hydro has come up with in its reliability planning, yes.

Q. Now, in the context of reliability and setting reserve margins, as a utility planner would you support or endorse a process whereby external social costs, externalities, are brought into this discussion of analysis when trying to set reserve margins?

A. I'm not sure I'm as familiar with the use of externalities to set reserve margin as I am with their use in determining which resources are going to be used to allow the utility to hit its target reserve margin. So, I guess I'm not really familiar with their use in the way you just described.

Q. Let me come at it this way.

We have talked about the way that Ontario Hydro incorporates their customer damage function or--

A. Okay.

Q. --customer outage function into their modelling. Would you agree with me that to a large extent that represents trying to monetize an external cost and bring that into the analysis?

A. Yes, I guess you could characterize it like that.

Q. If I put it to you that even that cost that Hydro incorporates, that really doesn't recognize the full costs that are associated with outages, particularly, for example, a lot of my clients, large industries, which would be devastated from a production point of view and a safety point of view and so forth, that perhaps that type of cost should also be brought into the process. Would you support that kind of analysis?

A. Well, as I said before, I wasn't sure exactly which costs were in the $5.91 figure, but I can certainly see a good argument for including the cost you have just mentioned.

Q. You said yourself in your direct evidence that trying to establish customer cost of outages is a very uncertain science?

A. Up to this point in time I consider it to be so, yes.

Q. Part of Hydro's evidence, when we talked about this issue, is that because it was so uncertain then perhaps there should be a caution in estimating reserve margins and err on the side of caution when setting reserve margins to account for this uncertainty because Hydro, like other utility planners, just aren't sure what the cost of outages are.

So my question to you: Is that an unreasonable approach to take?

A. Erring on the side of caution?

Q. Yes.

A. I think any utility planner would prefer to err on the side of caution.

Q. Now one final question. You told me that you didn't view the LOLP as a superior model and in fact I believe it's page 8 of your exhibit, you on the first full paragraph, halfway down that paragraph, you state:

> This approach to defining target system reliability is commonly called loss of load probability and is more widely used in North America than any

other single approach, although it is
gradually being supplanted by more
recently developed methods in some areas.

Could you tell me why this method is starting to be replaced by other methods?

A. For much the same reason as I believe Hydro uses its F&D value of service approach. There is increasing interest to try to bring more factors explicitly into the reliability planning method, so that attempts can be made to recognize factors that may be only implicitly recognized in LOLP. I have my own doubts as to how thoroughly developed these approaches are but the process does go on and in time these approaches could easily replace LOLP as a primary reliability modelling approach.

Q. I take it from your statement that I have read that utilities are in fact moving to different approaches.

A. There has been work on these approaches and a number of utilities, even ones that still rely on LOLP are looking at these alternative methods, looking to gain experience with them, and to see what the relationships are between these new methods and their traditional methods. So, in large respect the beat does go on, yes.

MR. RODGER: Thank you, sir. Those are all my questions.

THE CHAIRMAN: Thank you, Mr. Rodger

Is there anyone else that is going to cross-examine this witness before I call on Mr. Campbell? (No response)

Mr. Campbell.

MR. B. CAMPBELL: Thank you, Mr. Chairman. I'm going to rely on my friends to dig out references if I need them, so if I have to go and huddle from time to time to obtain the right references I ask your indulgence.

CROSS-EXAMINATION BY MR. B. CAMPBELL:

Q. Mr. Lanzalotta, one of Mr. Rodger's last questions prompted the answer from you that - I think I've got it right - you said "I think any utility planner would err on the side of caution." What I would like to ask you is what is your opinion of that. Do you agree that that is appropriate and proper?

A. If, where there are areas of uncertainty, yes, I think to err on the side of caution is more appropriate than to go the other way.

Q. So you agree that it is appropriate and proper where there are areas of uncertainty?

A. Yes, sir.

Q. Now I want then to take you to Exhibit 74 -- or Exhibit 87, rather, please, and page 74 of that exhibit.

That contains on that page a list of what are identified as some of the major factors affecting the amount of interconnection assistance. Do you see that list?

A. Yes, sir.

Q. I would like to run you down that and just see whether you agree that these are in fact some major factors affecting the amount of interconnection. assistance.

The first is seasonal and daily diversities of loads?

A. Yes, sir.

Q. And system size?

A. Yes.

Q. Planned reserves and hence target reliability?

A. I guess to an extent, yes.

Q. That is if a system that one was interconnected with had a very low planning reserve, that would affect the amount which you would be prepared to rely on?

[11:35 a.m.]

A. In an indirect sort of way. I assume that all utilities would set their reserve margins shooting for a target level of reliability.

Now, if a system feels it can hit its target level with a 16 per cent reserve margin and that level of reliability is the same that another system requires a 24 per cent reserve margin to hit, I don't think you could necessarily follow that you are going to be able to get a lot more assistance from the 24 per cent reserve margin system.

Q. But it's those kind of judgments you have to make. That's a factor you have to consider.

A. I believe it is a factor in determining it, yes.

Q. All right. Another factor that one has to consider is interconnection transfer capability available for emergency assistance taking into account firm and economy transfers and wheeling of power.

A. Firm transfers, yes. Economy transfers I sincerely have my doubts about.

Q. All right. Common cause events such as dry years, strikes, fuel shortages, generic faults, et cetera?

A. Very tangential influence. I don't consider this to be primary factors.

Q. If one was relying, for instance, if one was interconnected with a heavily hydraulic system and there had been a series of dry years such that their reservoirs were in pretty miserable shape, that would affect how much one could rely on that system?

A. It could affect how long one could rely on that system. You can rely on a system to a certain extent or for a certain duration.

The availability of water would definitely affect how much energy they could produce.

Q. All right.

A. It would not necessarily affect the amount of assistance they could give at first blush.

Q. At first blush. We will come back to a discussion of that difference a little later.

A. Okay.

Q. You would agree also that working agreements, regulatory, other obligations all impact on this?

A. Yes, sir.

Q. The correlation of load forecast errors between utilities is also a factor that has to be taken into account?

A. I'm not so sure on that one. I think that when economies are doing well, that most utilities

are seeing loads that perhaps are a little bit higher than what they had forecast. And when economies don't do well, I think that utilities across the board probably see things go the other way.

Q. If it could be demonstrated to you that in the ebb and flow of load forecasting uncertainty one's interconnected partners for a certain time period out in the future, sort of taking the experience of the past it could be shown that the load forecast error amongst one's interconnected partners were consistently in the same direction; that is, if over a period of time in the future based on experience and the fact in past it could be expected that at times of higher than expected load, all one's neighbours would also be experiencing higher than expected load, that would be a matter that would be relevant to this consideration; would it not?

A. Yes, although that relevance is tempered by whether or not all of these utilities peak in the same season, for example.

Q. Exactly, and that takes us back to our seasonal diversity.

A. If you have a winter peaking utility that is largely interconnected with summer peaking utilities, then the business about whether or not they

are above their load forecast all at the same time becomes much, much less critical.

Q. Again, though depending, as you have agreed with Mr. Watson, depending on how maintenance schedules are done and all of those kinds of considerations?

A. Yes, sir.

Q. The next example is, I won't read it all out, but it again has to do with the correlation of financial, social, environmental pressures which tend to cause utilities to move in the same direction at the same time. It's essentially the same point but a wider range of factors. With the same caveats you have put on the previous answer, you would agree that that is a factor that has to be taken into account?

A. To the extent they affect the reserves that are generally available from minute to minute, yes.

Q. New emissions regulations, that's an example of the kind of thing that could affect the amount of interconnection assistance?

A. I believe most emission regulations that I am familiar with make an allowance for system operating emergencies, this could have an effect as to what is running or what is being installed. But a lot

of the emissions regulations I am familiar with don't require you to let the system go dark, just to limit the amount of SO(2) that you are going to put out.

Q. But that is a short-term consideration in an operating context. I am trying to look at this in a long-term planning consideration where you are talking about making investment in a plant that won't come into service for many years in the future.

New emissions regulations, things like that, could affect the actual reserve that you have available as compared to what you planned for many years ago?

A. Pretty marginal relationship from my viewpoint.

Q. All right. I would like to ask you -- I guess the other matter I would like to clarify before I go on is, I take it you are aware that when you talk about reliance on 700 megawatts of interconnection capability, that is at peak time and that 2,000 megawatts is the figure used for off-peak times in Ontario Hydro's reliability calculations?

A. I looked only at the 700 megawatts.

Q. Now, you have indicated that based on your calculations, assuming the 700 megawatts of

interconnection support referred to in Ontario Hydro's evidence, you obtained a reserve margin expressed in percentage terms of 26 per cent. You have confirmed that several times.

A. It was in that range, yes.

Q. Now, am I correct that if you used -- you also explained that that was using Ontario Hydro's nuclear capability numbers.

A. Yes.

Q. Am I correct by analogy to your discussion when you were discussing some lower figures, am I correct that if you used Mr. Komanoff's nuclear figures, but Ontario Hydro's 700 megawatts of interconnection support, that in fact the percentage reserve margin would be higher than 26 per cent?

A. That's what I would expect.

Q. Have you done any calculation to quantify that? I think you said it made 2 percentage points difference.

A. It seemed to at of the 16 per cent level. I'm not sure it would be the same percentage, but no, I haven't done the calculation.

Q. But directionally it would lead one to conclude that a higher per cent was necessary, I think you have confirmed.

A. Yes.

Q. Now, I want to turn then to the discussion of customer interruption costs and your concerns which seem to revolve around whether a customer would pay for that kind of money for that kind of capacity, the 5.91 figure, for instance, that's mentioned in your paper and you mentioned this morning.

I want to put to you an analogy, dangerous as these things often are. What usually happens to me in these circumstances, it leads to Dr. Connell putting a hypothetical to me, which I am completely incapable of dealing with, so I want you to understand that I do not view this as a risk-free proposition.

But it seems to me that at the simplest level, reserve margin, it's sort of like the spare tire in your car.

A. Yes.

Q. If something happens to you, you can keep going hopefully.

A. Yes.

Q. You can get your hands a little dirty but you can keep on going.

A. Yes.

Q. Now, reserve margin is not all made

up of the same kind of resources. Reserve margin is a system thing in the end; is it not?

A. Yes.

Q. And similarly with the spare tire, the modern day spare tire in many cars is not the same thing as is on the four wheels of the car. When you buy it there is a stupid little tire inside your trunk. Are you familiar with that?

A. Yes.

Q. Presumably some part of the price you pay for the car is for that stupid little spare tire.

A. That's correct.

Q. I would like you to sort of assume it's $50. I don't know what it is, but assume it's $50.

Now, isn't it fair to say that if one has to use that tire - modern tires are very reliable, don't have to use it often - but say I stagger out one winter morning and see that I have a flat tire, I have to use that stupid little tire to take me two miles to where I can get my real tire repaired. Are you with me so far?

A. Yes.

Q. Now, if that's the only time I have to use that, that tire is costing my $25 a mile in

actual use; is that correct? Two miles costs me $50.

A. I guess that's one way to look at it.

Q. Okay. And whereas if I had to pay $25 a mile for my regular tires, of course that would be something that I could not possibly afford.

A. Okay.

Q. Now, isn't the analogy exactly apt with respect to the kind of customer damage costs. It's not that the $5.91 per kilowatthour is something that anybody would be prepared to pay all the time, it is just that at that particular moment in time, the fact in my analogy that I spent the 50 bucks on the stupid little spare tire, seems like a helluva a good investment; does it not?

A. I can't answer how it seems to you, although it is an interesting analogy --

Q. I remind you that it was wintertime.

A. I could see where you would have been grateful for having spent the $50, yes.

Q. Similarly, to the extent that someone is buying -- Mr. Rodger's client is buying a tonne of electricity and requires a very reliable supply, similarly is it not conceivable that that $5.91 for the particular time that he needs it, seems like a great deal. If you have reviewed any of his previous

cross-examinations, he has talked about the effect on the Ford, he cross-examined our witnesses on the effects on the Ford production line and robotics, and in that circumstance it may be that for that little period of time, pick the one day in 10 years, that seems like a great bargain.

A. I'm sure to Mr. Rodger it would.

Q. Now, I want to then talk to you a little bit about reserve from the point of view of the operating time frame, the daily running of the power system, and the planning time frame. You do see a distinction between those time frames.

A. Yes, I think so.

Q. And it is relevant to reserve considerations.

A. Well, I am not sure in what context you want it to be relative.

What happens during on-peak periods is much, much more relevant to reserve margin considerations I think than what happens during the rest of the time.

Q. All right. In making that statement have you had an opportunity to review Mr. Barrie's testimony in direct on behalf of Ontario Hydro where he dealt with what Hydro sees as the important differences

when one is considering an operating time frame versus a planning time frame?

A. I am not sure that I have.

Q. Well then, let me walk you through it this way. I guess I would like to start by, take the situation, the interconnected system there is an outage, instantaneous outage. The first thing that happens, as you have pointed out, is that there are automatic draws over the ties, there is instantaneous support available, at least up to the limits that are associated with the various transmission systems; is that correct?

A. Yes, sir.

Q. Now, the minute that starts happening, am I not correct that certainly in the NPCC, but generally, the instant that starts happening there is an obligation placed on those interconnected partners to replace operating reserve, that is Ontario Hydro is pulling from the south, it can only do one of two things: It has to, in 10 minutes as the rule is here, get up more operating reserve on its system to bring those flows back down to zero, or to where they were previously, or it has to contract and be capable of receiving over the intervening transmission system for an equivalent amount of operating reserve.

A. Yes, I believe that's correct.

Q. So that the situation cannot be allowed to persist where Ontario Hydro is leaning on the ties, leaning on the spinning reserve, or leaning on the operating reserve of another system, that is not a proper, long-term operating condition -- short term, 10 minutes you are supposed to be back to regular.

A. Well, in 10 minutes you either make arrangements to firm up those reserves that you are receiving from the interconnected system, they may be able to obtain additional reserves either from their system or the utilities with which they are interconnected.

But you're right, I mean, this instantaneous--

Q. In 10 minutes though that has to be worked out.

A. --flow, you have got to do something with it in the 10 minutes.

Q. What you have got to do is replace that operating reserve that you are required to carry?

A. Somehow, that's what everyone attempts to do, yes.

Q. If one is looking for it from someone else beyond the 10 minutes, then you have to obtain it,

you have to -- then one's ability to obtain it may be affected by intervening transmission limits?

A. Yes.

Q. And they could be affected by transmission limits on one's own system?

A. That's correct.

Q. I take it that not having reviewed Mr. Barrie's testimony, you are not aware of the fact that there have been times when transmission limits, for instance, in Michigan made it impossible for Ontario Hydro to get any more than 350 megawatts on that basis.

A. I'm sure that there are times when that's the case. I only know that that is in no way addressing what the firm transactions over those ties were. It may be, in fact, that Michigan is producing a large ability of generation for Hydro at that point, so that Hydro can reduce its sulphur dioxide emissions. I know that is a fairly common occurrence too. When that is it happening, you are right, you are limited as to the additional power you can get over that tie.

Q. Or if there are other limitations and one is not taking anything from Michigan previously.

A. I just don't know the context in which Mr. Barrie produced this number. I can see that

there are operating conditions that affect the first contingency incremental transfer capability, yes, if that's your question.

Q. I take it you don't argue with the figures that on a more -- I am not trying to put forward the 350 as that's most of the time. Don't take me wrong.

A. Okay.

Q. I take it, though, that you would have no argument with Hydro's response in I think it is Interrogatory 2.7.7, which is included in your material, which says the range, it talks there of a range between 1,500 and 3,100 being the maximum ever taken over the lines. You wouldn't argue with those figures, the history as reported by Hydro?

A. No. That is the history of what Hydro has taken historically. No, I have no quarrel with that.

Q. What I am suggesting to you is the history of the limits on what Hydro could take, the various limits have resulted in a range of that magnitude?

A. If anything, those historical numbers seemed to give me a little bit of confidence that my 3,200 number was reasonable in that historically Hydro

very seldom but occasionally has found it in a position where it had to and was able to import from the south almost the 3,200 megawatts that I use. Using that in a one day in 10 year LOLP, That's about how often we would expect Hydro to have to make full use of that capability. It may be a little bit more often, but...

Q. But if the pattern of those limits floated much more - and I will pick a number, again I use it as an example, I am not trying to tie you to a number.

A. Okay.

Q. If the pattern of what the transmission limits either in Michigan or Ontario or transient, whatever they are, if the pattern of those limits, for instance, was such that, one, that the capability of taking the higher end of that range, that only occurred in very rare circumstances and it tended not to be at Hydro's peak time for instance, then it would be inappropriate to use that higher number, given the assumptions I have put to you.

[11:55 a.m.]

A. Yes. Although I don't want to confuse a historical record of what Hydro has taken over the tie and say that that number reflects all that Hydro could have taken over the tie at those times.

The 15 to 3100 range reflected to me Hydro's historical experience in making use of these ties. I didn't want to confuse that with what the capabilities of those ties are.

Q. Well, let me take you back to this time frame that I'm talking about, the operating, and continue with my development of what's happening in this circumstance as we move through time.

A. Okay.

Q. Because I do want to focus in on this operating versus planning time frame.

Now in our ten minutes, the transmission limits are what the transmission limits are, whatever support is available is available. But the thing I would like to key on is that -- to remind us where we are picking up, which is at the end of the ten minutes, the obligation arises to put in place, to replace that operating reserve.

A. That's correct.

Q. That's where we got to.

A. Yes.

Q. Now it seems to me at that point that the pertinent question for a planning hearing is: Have decisions been made five years earlier, or whatever the lead time is, have decisions been made in sufficient

time that once one deals with the emergency support in whatever amount, somewhere there is existing and isn't the obligation on each utility specifically placed on each utility to put in place in a situation such that after the reserve, after the ten-minute emergency is over, they can rely on there being adequate capacity in place to replace that reserve?

A. On their own system --

Q. That has to be done?

A. On their own system?

Q. Yes.

A. I don't know of all that many utilities that assume that those ties can only be used for ten minutes of emergency assistance --

Q. No, I'm saying, I'm going to take you one step farther then and that the judgment that is made for reserve reasons is not -- for long-term planning reserve is not associated with the ten-minute support but it's associated with the judgment of if I have to rely on my neighbours for a longer period of time, weeks, months, who knows what, how much can I rely on my neighbours not for the instantaneous support but rather for the support that replaces the requirement to get operating reserve on both systems back up to a reasonable level within ten minutes. Now

as I move into the time period, isn't that the relevant consideration?

A. First of all, it's a pretty long question, you've covered a lot of ground. Let me say --

Q. Let me back it up. Let me back it up. You've talked about instantaneous support being available out of people's operating reserve; correct?

A. That's correct.

Q. The obligation remains to replace that operating reserve one way or the other if you draw on it?

A. To firm up who is providing it and compensate them for it or to have it provided from another source. To do something to -- I mean you can go the first ten minutes and the ties will draw whatever the laws of physics say that they will draw; and then at that point you have to contractually firm up who is going to provide what reserves, but adequate reserves have to be provided.

Q. And depending on the kinds of outages that you're facing, that reserve may have to be provided for some considerable period of time?

A. Yes. Although we don't, I don't think we go into this assuming it is going to have to

be provided for months as you imply, as you said --

Q. Some considerable period of time?

A. Some period of time.

Q. And so a judgment has --

A. I don't know if it's considerable or not.

Q. Well, certainly you can't go beyond the ten minutes and you may face outages of a wide variety of nature that may take you for days, weeks, months. It depends on the nature of the outage; correct?

A. It can, yes.

Q. But the obligation to replace that operating, to replace that generation in effect, never mind whether it's operating, what it is, the obligation to replace that generation remains?

A. Yes, sir.

Q. For that full time period whatever it is?

A. Yes.

Q. So that the pertinent planning question I suggest to you is not what happens in the 10 minutes but to make a judgment looking at one's interconnected neighbours as to what is a reasonable number to rely on for some reasonable period of time

after the 10 minutes?

A. I think we have tried to look at those things in my analysis, yes.

Q. But you agree with my proposition? It's not the 10 minutes that counts; it's in a planning sense looking ahead, you've got to look beyond the 10 minutes of instantaneous support and make a judgment, the utility has to make a judgment as to how many megawatts it can rely on over that following period?

A. I think both are important. I don't say for planning purposes you can ignore the 10 minutes --

Q. I haven't suggested that.

A. Because if you do I think your system will be dark within the first 10 minutes.

Q. I haven't suggested that.

A. Okay.

Q. But I'm suggesting that you do need to consider when you're putting in place your plans how much can you rely on for a much longer period of time in comparison to the 10 minutes.

A. Yes, sir. And I believe I have.

Q. Now if one is considering in this mix as well in a planning time frame items such as load forecast errors and how volatile those are, I would

like to take the thought of you've got to worry about longer than 10 minutes. And is your judgment about how long you have to worry about, isn't it influenced by your perception of how long load forecast areas are likely to persist as well because we are now talking in time periods that are well out in the future when one is planning?

A. Where in Ontario Hydro's case we're looking southward, all of the systems that it is interconnecting with in general are going to be summer peaking to Hydro's winter peaking, I don't see that the fact that Hydro's winter peak is higher than what it expected at the same time that New York's summer peak is higher than what it expected to be nearly as relevant as if they would be if both systems were winter peaking.

Q. But you would agree that all of that is tempered by maintenance considerations on that summer peaking system? What they in fact have available in the winter, which is their lower period?

A. Well, again the maintenance is of primary concern in the short term. In the long term you know that if Ontario Hydro has an extraordinary need, the systems to the south -- if all that is required to keep the lights burning is to defer

maintenance or to bring back units on which maintenance is being performed, you know that those systems will do the utmost to see that that is done, as would Ontario Hydro on their behalf if they had the need.

Q. I agree. And the utilities' practices in doing that are relevant considerations in all of that?

A. Yes.

Q. As are the kinds of limitations that are being experienced on the transmission system for instance south of Lake Erie?

A. Okay.

Q. You would agree with that?

A. I agree that transmission system limitations are relevant, yes.

Q. All right now. I'm a little confused about that part of your written testimony that relates to integrating the costs of transmission into planning.

I don't want to bore everybody by taking the Board through and you through a series of references that indicate that Ontario Hydro has included what it sees as appropriate allowances for inter-area transmission, appropriate allowances for radial transmission, appropriate allowances for having to add those things in areas where there are

transmission limitations. I could give you a whole series of references to Ontario Hydro's evidence where I think the theme is quite clear that it's Ontario Hydro has, given the planning context of this hearing, tried to capture an appropriate cost, for instance, for additions to the transmission system generally over the period that address limitations. We prepared an undertaking response for Dr. Connell on that matter that talked about the major limitations and the steps. I could take you through a whole bunch of stuff on that.

I don't understand how on the face of all of that evidence you see a disparity in the treatment of transmission costs as between Ontario Hydro's supply options and non-utility generation?

A. I guess the thrust of what I tried to say in here, and maybe I said it poorly, is that Hydro should not rule out purchases from non-utility generators on transmission considerations when it wouldn't use these same considerations to rule out generating facilities of its own.

Q. But you would agree, I take it, that the appropriate thing to do is that if Hydro is looking at a supply facility in a particular area and it was going to -- if it was going to add a supply facility,

it needs to include incremental transmission costs for that facility; and similarly if a non-utility generator triggered a requirement for additional transmission to service it, in particular, that that cost should be borne. What you've said, as I understand it, is there should be an even treatment of these kinds of costs?

A. That's pretty much my position.

Q. Now in face of all of the evidence that Hydro has given on that matter, and I can refer you to a variety of attempts where I think they have gone through some attempts to try and show that given the planning level that we are operating at there has been every attempt to do that, I don't understand your complaint.

A. Well, my review of the transmission system, limited as it might have been, indicated at least on the bulk system, that systems reasonably heavily loaded, it can withstand single contingency as far as I can tell in most conditions, but that any time Hydro goes into install a new major base load facility, it's going to have to install additional transmission.

Now, if in fact that is the case - and again I want to limit that by the quality of my analysis, I was limited on this - but to the extent that that is true, I thought it was not fair for Hydro

to say to non-utility generators, okay, if you locate here, here or here, we don't have enough transmission to take care of you there so we're not going to buy from you if you're there. Or we are going to discourage it from there. When in fact almost regardless of where Hydro puts its facilities, it's going to need additional transmission too.

Q. But would that not be perfectly fair if, as I say is the case, the evidence shows that Hydro has captured the cost of additions to both its inter-area transmission system and the radial transmission to incorporate generation, if those costs have been fairly captured, taking into account that there may be areas in which there are worse problems and less problems, those costs have been fairly captured, then your problem goes away, doesn't it?

A. You mean in terms of the avoided costs payable to these NUGs?

Q. Yes.

A. Well --

Q. Both the avoided costs payable to the NUGs and, the flip side of the coin, the supply costs calculated for Hydro's supply options?

A. If I'm a non-utility generator located in one of these areas where Hydro says it

doesn't want to buy from, then whatever is included in the avoided cost is kind of irrelevant. I'm not going to be able to get that cost at all.

I see that there may be a connection but it's -- I'm not complaining in here about what Hydro is including in its avoided cost. What I'm complaining about in here or what I'm trying to address is the concept that Hydro is not going to buy from a non-utility generator because the transmission system would need beefing up in a particular area for that to happen.

Q. But my point is simply this: To the extent that Hydro's has been equitable in costing its own supply appropriately to incorporate these additional transmission costs, and I submit that they have been both identified and included--

A. Hm-hmm.

Q. --then that is a fair treatment of supply options? All that's being said to the NUGs, potential NUGs, potential NUGs, is that if you want to put stuff onto our system, these are areas where we would encourage it and these are areas where we are trying to tell you fairly upfront that you are going to trigger an additional transmission charge, same way we would do with our own facilities.

A. Yes. Well, if the NUG is being treated completely the same as Hydro treats its own generating facilities, it's difficult to have an argument. I just don't know that that's the case, and that certainly wasn't the impression that I was getting from the map with the shaded areas that essentially said, we may not be able to help you here.

Q. So that taking hypothetically -- I know you haven't had a chance to review all of this.

A. Okay.

Q. But taking hypothetically as a fact that there is reasonable equity as between the treatment of Hydro's supply costs with respect to transmission and NUGs' costs with respect to transmission, then you would agree you don't have an argument?

A. Assuming that there is that equitable treatment, pretty much of what I'm addressing here seems to be happening already.

Q. So that you would agree that there isn't an argument to be had if the treatment is equitable?

A. Well, this is a hypothetical you say.

Q. Yes.

A. If everybody is being treated the

same, then life is beautiful.

Q. So this argument disappears?

A. In your hypothetical.

Q. Fine. That's all I need. Thank you.

Mr. Chairman, I want to distribute an interrogatory which was an interrogatory MEA submitted to Mr. Lanzalotta. And if I could get the next number for that, please, the interrogatory number is B7.9.17.

THE REGISTRAR: 781.5.

---EXHIBIT NO. 781.5: Interrogatory No. B7.9.17.

THE WITNESS: Could I have that interrogatory number again.

MR. B. CAMPBELL: I'm sorry, I should give you a copy. I thought you would have a copy.

THE WITNESS: I have a copy of all of them; I just didn't know which one.

MR. B. CAMPBELL: The number is on the upper right-hand corner.

THE WITNESS: Okay.

MR. B. CAMPBELL: Q. Now as I understand it, this was an interrogatory asked by MEA in which they asked for your loss of load probability model; am I correct? That's what it says?

A. Yes.

Q. And what you said was that the LOLP

model used is a proprietary program which is used only by Whitfield Russell Associates and which has no formal documentation. And then you provided input and output data. That was your answer and you stand by it?

[12:15 p.m.]

A. Yes, sir.

Q. Now, in the same way that you raised concerns, does that not raise concerns about the workability of the model, the ability to trace the results and the inability to review variations which may be introduced for analytic purposes?

A. Well, I might note that our LOLP model which I have authored is relatively simple. It's a simple straightforward calculation. I am sure if any of the parties or intervenors had asked for the model we would have provided it under a confidentiality agreement, and they would have found it was very easy to run and very easy to duplicate the results that we had gotten. However, nobody asked for for it.

Insofar as the documentation goes, I feel very comfortable using it simply because I'm the one that wrote it.

Q. And the people at Ontario Hydro may be in exactly the same position with their model.

A. Yes. Although I'm not sure that

given how long this model has been around, that the same person that has written it is available to direct its use.

Also I might note that despite our attempts and considerable use of budget, we weren't able to run it.

MR. B. CAMPBELL: Finally, Mr. Chairman, I would ask for a little guidance on this. We have received interrogatories only over the last day or so in many respects, and I guess sort of have a choice, there is some material in there on which we want to rely and I can either -- I think there are about 20-odd, 22 interrogatories that have been answered by this witness.

MR. D. POCH: Could you tell us, asked by who?

MR. B. CAMPBELL: A variety of parties, MEA in particular.

What I would like to do is simply provide a list of those, or alternatively, if I could have some more time, as I say some of them we only got yesterday, if we could have some more time we could be slightly more selective in determining what we should file.

THE CHAIRMAN: This came up during cross-examinations, there were people who put

interrogatories in and they were put in as part of the evidence, although they were not specifically referred to the witness, there were several instances where that occurred, and those interrogatories then became part of the evidence.

MR. B. CAMPBELL: Fine. Then I would simply ask that we will provide a list of the interrogatories which we intend to rely on and I ask that they be added to --

THE CHAIRMAN: Let me make sure I understand. These are interrogatories addressed to this witness in which he provided answers?

MR. B. CAMPBELL: Yes. So we will provide a list and we will add them to the exhibit number.

I would have preferred to be a little more selective, but we just haven't had time given the time when we received them.

Thank you, Mr. Chairman.

THE CHAIRMAN: Do you have a list now?

MR. B. CAMPBELL: No, I do not. As I say, we were receiving material yesterday.

In any event, those are all of the questions I wanted to ask. Thank you very much.

THE CHAIRMAN: Before I get to you, Mr.

Starkman, is there anyone else who wants to ask any further questions? Mr. Watson, Mr. Rodger, do you have any further questions?

MR. R. WATSON: No, sir.

MR. RODGER: No, thank you.

THE CHAIRMAN: Do you have a question?

EXAMINATION BY DR. CONNELL:

Q. Mr. Lanzalotta, I wonder if you could help me to understand whether in reading your brief, Exhibit 744, whether I should simply read it as a critique of Hydro's approach to reserve margin, or would you suggest that I should take your recommendations as a fully adequate substitute for Hydro's own judgment about reserve margin?

A. It was definitely a critique of the way Hydro produced its reserve margin. However, there was substantial analysis that went into this study and it was intended to recommend that a 20 per cent planning reserve margin should be entirely reasonable for use by Ontario Hydro.

Q. Now, if you were yourself, let us say, the chief executive officer of a public utility and were looking to your own staff for policy advice on reserve margin, would the kind of analysis that you have presented here be adequate in your judgment?

A. I think for many years this is exactly the type of analysis that utilities have relied on, so in short, yes, I believe so.

Q. Do you think it is possible if your staff presented you with this kind of analysis, you would suggest to them that they should go back and develop a different kind of model to substantiate it, to have a run at it in two different ways?

A. It's entirely possible that I would.

As I said before, utility planners tend to err on the side of caution, especially when there are unknowns.

I would have preferred to have been able to actually use the F&D model. I feel that I probably could have come up with results very similar to this had I been using that.

And in fact, if you look at Hydro's own studies where they produce -- they produce a curve which shows the minimum cost to supply electricity. Taking into account both the supply side cost and the outage costs, there is a range over which these minimum costs are achieved, and the 20 per cent reserve margin I am recommending happens to be very close to if not on the lower end of that cost range, even considering Hydro's own approach.

To be sure, over this range at one end you have lower generation costs and higher outage costs and at the other end you have higher generation costs and lower outage costs, but there is a range over which these costs are effectively minimized. And it's -- even Hydro's own study is not completely inconsistent with the choice of 20 per cent as a planning target.

Q. Let me push my hypothetical a little farther. If your staff did present the two different approaches and they gave you different answers, obviously you would try to find out why, but if you were unable to come to the conclusion that one approach was more meritorious than the other, how would you proceed? Would you pick a number in between or would you flip a coin, or what?

A. Well, I would try to go for more analysis or to find out why the difference is occurring.

Planning engineers are going to be very reluctant to pick a number that might be -- that might contain unexplained risks without exactly understanding what those risks are.

From a planning viewpoint, the engineers tend to be very conservative and they don't want to go out on a limb. If I were in that position, I might

react that same way.

Q. You testified at the beginning that you had been a witness in several other hearings for other utilities, are there any parallel cases in which you made a recommendation for a reserve marriage which was lower than that which was proposed by the utility?

A. Yes. The most dramatic case was the case involving Duquesne Light Company. It's one of the cases to which I referred when Mr. Starkman lead me through my list of appearances.

In that case the utility was trying to bring in to rates a portion of two new nuclear units and as a result its reserve margin was going quite high. It attempted to convince the Pennsylvannia Commission that a 25 to 26 per cent reserve margin was appropriate for these purposes.

I went in and used essentially the same LOLP model that we used here and recommended that the one day in 10 year target was achieved using -- with a reserve margin from 18 to 22 per cent, and the Commission recognized that for reliability planning purposes, that reserve margin was appropriate rather than the 25 to 26 per cent.

Although the Commission then said that for social impact purposes, given the huge amounts of

load which Duquesne had lost due to changes in the steel industry, that for ratemaking purposes they would probably allow more of the plant into rates than was necessary to achieve the 18 to 22 per cent reserve margin.

Q. In that particular case was the kind analysis done by the utility similar to your own?

A. Essentially what they did was they backed into the 25/26 per cent, not so much on a rigorous mathematical basis, but using empirical argument, looking at other utilities and looking at reserve margins that other utilities were carrying at that time.

Of course at that time many of the utilities were carrying high reserve margins because of a slowdown in load growth and a continuation of the construction program for these large units.

So they used that type of argument rather than a strict mathematical analysis. And I used the mathematical analysis to try to bring us all back to a common point.

Q. So Hydro's approach in fact had more analytical depth to it than the parallel case that you are referring to?

A. Very much so, yes.

DR. CONNELL: Thank you.

THE CHAIRMAN: Mr. Starkman, do you have any questions in re-examination?

MR. STARKMAN: I just have two very brief questions.

RE-DIRECT EXAMINATION BY MR. STARKMAN:

Q. Mr. Lanzalotta, there has been lots of discussion, particularly with the recent question of Dr. Connell, about the F&D and LOLP. I just want to be clear. Is the difference in results, I am talking about the 24 and 20, does that come from the model that was used or from the assumptions that one placed into the model?

A. I think it's largely driven by the assumptions.

Q. Mr. Campbell brought up this interrogatory, this MEA question about the availability of your LOLP. If you look at appendix 9 of Exhibit 745, and I am looking at about -- someway through the piece, there is a memo from yourself to myself dated July 16, 1991. It's about 16 or 17 pages into that appendix 9.

THE CHAIRMAN: Is that the note of David Argue?

MR. STARKMAN: It says to David Argue,

yes, July 16, 1991.

Q. Do you have that, Mr. Lanzalotta?

A. Yes, I do.

Q. I am looking at the second page of that memo. I guess my question is: Did you ask Mr. Taborek or Ontario Hydro to make some runs on their F&D model using your assumptions or using different assumptions?

A. Yes, we did.

Q. Do you recall what the reply was? Does this memo record that transaction of that business?

A. Yes, I believe it does. From what I recall, and I think it's as I related here, at first Mr. Taborek was unsure, he went back and checked with other people at Ontario Hydro, and then they got back to us and said that they would not be able to make those runs for us.

---Witness withdraws.

MR. STARKMAN: Mr. Chairman, those are my questions.

I just had one comment about Mr. Campbell's request to file these interrogatoriy answers. I just want to indicate, we have no objection to those interrogatory answers being filed, but I would

indicate that Ontario Hydro asked no interrogatories of Mr. Lanzalotta. So the interrogatories he is referring to are ones that were asked I believe by either the MEA or AMPCO, and we did provide those answers last week. So I don't know, I just don't want it to thought that we didn't answer questions that were posed to us or we didn't answer them in a timely fashion.

THE CHAIRMAN: I didn't get that suggestion from Mr. Campbell. But I think just because they were asked by another party doesn't mean that they can't be put in if there were a response by this particular witness.

MR. STARKMAN: No, we have no difficulty with that.

THE CHAIRMAN: Does that complete our work for today?

It's a delightful way to be doing things.

We start again tomorrow morning at nine o'clock when we have Northwatch, I believe, and then on Thursday we have Mr. Watson's witnesses.

MR. R. WATSON: Yes, sir.

THE CHAIRMAN: We will adjourn until tomorrow morning.

THE REGISTRAR: Please come to order. This hearing is adjourned until nine o'clock tomorrow

morning.

---Whereupon the hearing was adjourned at 12:30 p.m., to be reconvened on Wednesday, October 28, 1992, at 9:00 a.m.

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